CARRIZO OIL & GAS INC
Form 10-K
April 02, 2007

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UNITED STATES SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549
Form 10-K
Annual Report Pursuant to Section 13 or 15(d)
of the Securities Exchange Act of 1934
For the Fiscal Year Ended December 31, 2006
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, $.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. þ

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, or a non-accelerated filer. See definition of accelerated filer and large accelerated filer in Rule 12b-2 of the Exchange Act (Check one):

Large accelerated filer o Accelerated filer þ Non-accelerated filer 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, 2006, the aggregate market value of the registrant s Common Stock held by non-affiliates of the registrant was approximately $656.7 million based on the closing price of such stock on such date of $31.31.

At March 1, 2007, the number of shares outstanding of the registrant s Common Stock was 25,991,485.

DOCUMENTS INCORPORATED BY REFERENCE

Portions of the definitive proxy statement for the Registrant s 2007 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, 2006.

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PART I
Item 1. and Item 2. Business and Properties
General

Carrizo Oil & Gas, Inc. (Carrizo, the Company or We) is an independent energy company engaged in the exploration, development and production of natural gas and oil. Our current operations are focused in proven, producing natural gas and oil geologic trends along the onshore Gulf Coast area in Texas and Louisiana, primarily in the Miocene, Wilcox, Frio and Vicksburg trends, and, since mid-2003, in the Barnett Shale area in North Texas. Our other interests include properties in East Texas, the U.K. North Sea, and acreage in shale plays in the Barnett/Woodford in West Texas/New Mexico, Floyd/Neal in Mississippi, the western New Albany in Kentucky/Illinois and the Fayetteville in Arkansas. We also have a coalbed methane investment in the Rocky Mountains.

We have traditionally grown our production through our 3-D seismic-driven exploratory drilling program. Our compound production growth rate for the period December 31, 2000 through December 31, 2006 on an annualized basis was 17%. From our inception through December 31, 2006, we participated in the drilling of 508 wells (200.3 net) with an apparent success rate of approximately 71% in our onshore Gulf Coast area and an apparent success rate of 100% in the Barnett Shale area in North Texas (also called Barnett Shale area or Ft. Worth Barnett Shale area). Exploratory wells accounted for 81% of the total wells we drilled. Our total proved reserves as of December 31, 2006 were an estimated 210.0 Bcfe with a PV-10 value of $387.2 million. During 2006, we added a record 71.1 Bcfe to proved reserves and produced a record 11.7 Bcfe. We finance the majority of our drilling activity through internal cash flow generated primarily from oil and natural gas production sales revenue, proceeds from the issuance of various securities and borrowings under our credit facilities.

As a main component of our business strategy, we have acquired licenses for over 11,800 square miles of 3-D seismic data for processing and evaluation. Historically, we either (1) sought to acquire seismic permits from landowners that included options to lease the acreage prior to conducting proprietary surveys or (2) participated in 3-D group shoots in which we typically sought to obtain leases or farm-ins rather than lease options. Since 2001, we have been able to increase the size of our 3-D seismic holdings in our onshore Gulf Coast area by approximately 195% to over 8,400 square miles, in large part by taking advantage of very favorable pricing available for nonproprietary data from libraries of seismic companies. Since 2003, we have also grown our 3-D seismic holdings in the Barnett Shale area to over 386 square miles.

One of our primary strengths is the experience of our management and technical staff in the development, processing and analysis of this 3-D seismic data to generate and drill natural gas and oil prospects. Our technical and operating employees have an average of over 20 years of industry experience, in many cases with major and large independent oil and gas companies, including Shell Oil, Ocean Energy, ARCO, Conoco, Burlington Resources, Unocal, Pennzoil and Tenneco. Analyzing and reprocessing our 3-D seismic database, our highly qualified technical staff is continually adding to and refining our substantial inventory of drilling locations.

We believe that our utilization of large-scale 3-D seismic surveys and related technology allows us to create and maintain a multiyear inventory of high-quality exploration prospects. As of December 31, 2006, we had 194,719 net acres in Texas and Louisiana under lease or lease option (all references to acres under lease in this Form 10-K also include lease option acres unless otherwise indicated), including 37,644 net acres in our onshore Gulf Coast area, predominantly all covered by 3-D seismic data, 86,752 net acres in our Ft. Worth Barnett Shale area and 65,506 net acres in our West Texas Woodford/Barnett Shale area. We have identified: (1) 191 potential exploratory drilling locations in our onshore Gulf Coast area, comprised of 106 leased exploratory drillsites, 55 of which are field extension wells based on initial drilling activities, and 85 seismically defined prospects on which we are pursuing acreage, and (2) over 675 potential exploratory and development horizontal drilling locations on our leased acreage in the Ft. Worth Barnett Shale area. The vast majority of our 3-D seismic data covers productive geological trends in our onshore Gulf Coast area, where we have made 265 completions as a result of our utilization and evaluation of this data.

In our onshore Gulf Coast area, most of our drilling targets prior to 2000 were shallow (from 4,000 to 7,000 feet), normally pressured reservoirs that generally involved moderate cost (typically $0.3 million to $0.4 million per completed well) and risk. Since then, the depth of many of the wells that we have drilled, as well as our current drilling prospects, are deeper, over-pressured targets with greater economic potential but generally higher cost (typically $1.0 million to $4.0 million per completed well) and risk. We seek to sell a portion of these deeper prospects to reduce our exploration risk and financial exposure while retaining significant upside potential. More recently, we have begun to retain larger percentages of, and increased our exposure to, higher cost, higher potential wells.

In mid-2003, we became active in the Barnett Shale area in North Texas (primarily in the Tarrant, Parker, Denton, Johnson, Hill and Erath counties). Improvements in fracture techniques in recent years have dramatically changed the economics of producing reserves in the Barnett Shale, which is now considered one of the most active natural gas plays in North America. The reserve profile from the typical productive wells we drill in the Barnett Shale area is noteably longer-lived compared to the typical reserve profile from our wells drilled in our onshore Gulf Coast area.

We are drilling primarily horizontal wells in the Barnett Shale area. Typical costs to drill and complete are approximately $2.4 million for horizontal wells. Our Barnett horizontal wells generally have target depths of 8,500 to 10,500 feet including the lateral section. During 2006, we held an average 74 percent working interest participation in the Barnett wells drilled as we shifted to a primarily Carrizo-operated program and operated a majority of the wells drilled. For wells drilled in 2007, we plan to increase our average working interests to between 80 and 90 percent.

Accordingly, we believe that continued development of producing reserves in the Barnett Shale play will have the potential to lengthen our overall average reserve life and, on balance, add a long-lived cash flow stream to help fund our future capital exploration and development program. In our Barnett Shale area through December 31, 2006, we had acquired 86,752 net acres, drilled 122 gross (71.7 net) wells and increased our total proved reserves in the Barnett Shale area to 146.6 Bcfe. As of March 20, 2007, our current net production in the Barnett Shale area was estimated at 21 MMcfe/d.

As of December 31, 2006, we operated 119 producing oil and gas wells, which accounted for 55% of the onshore Gulf Coast area producing wells and 36% of the Barnett Shale producing wells in which we had an interest.

During 2001, through our wholly-owned subsidiary, CCBM, Inc. (CCBM), we acquired 50% of the working interests held by Rocky Mountain Gas, Inc. (RMG) in approximately 107,000 net mineral acres prospective for coalbed methane located in the Powder River Basin in Wyoming and Montana. In 2003, we contributed a majority of our coalbed methane property interests into a newly formed company, Pinnacle Gas Resources, Inc. (Pinnacle), in return for an interest in Pinnacle. As of December 31, 2006, we owned approximately 9.5% of the common stock of Pinnacle on a fully diluted basis. For more information on this contribution and our investment in Pinnacle, please read Pinnacle Transaction below.

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

Business Strategy

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:

Grow Primarily Through Drilling. We are pursuing an active 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 83% over the last three years and a 100% drilling success rate in our Barnett Shale area since inception in 2003. During 2007, we are drilling or plan to drill approximately 15 wells (7.0 net) in the onshore Gulf Coast area and 53 wells (46.6 net) in the Barnett Shale area. We have planned approximately $165.0 million to $175.0 million for capital expenditures in 2007, $143.9 million of which we expect to use for drilling activities in the onshore Gulf Coast and Barnett Shale areas.

Focus on Prolific and Industry-Proven Trends. We focus our activities both in the prolific onshore Gulf Cost area where our management, our technical staff and our field operations teams have significant prior experience and in the industry-proven Barnett Shale trend in which our wells have generally longer-lived reserves. Although we have broadened our areas of operations to include the Rocky Mountains, the U.K. North Sea and shale trends in West Texas/New Mexico, Mississippi/Alabama, Kentucky and Arkansas, we plan to focus a majority of our near-term capital expenditures in the onshore Gulf Coast area, where we believe our accumulated data and knowledge base provide a competitive advantage, and in the Barnett Shale area in North Texas, where we have acquired a significant acreage position and accumulated a large drillsite inventory.

Aggressively Evaluate 3-D Seismic Data and Acquire Acreage to Maintain a Large Drillsite Inventory. We have accumulated and continue to add to a multiyear inventory of 3-D seismic and geologic data along the prolific producing trend of the onshore Gulf Coast area and industry-proven trend of the Barnett Shale area. In 2006, we added approximately 761 square miles of newly released 3-D and seismic data. We believe our utilization of large-scale 3-D seismic surveys and related technology provides us with the opportunity to maximize our exploration success in both the onshore Gulf Coast and Barnett Shale areas. As of December 31, 2006, we had accumulated licenses for approximately 11,797 square miles of 3-D seismic data and identified over 866 drilling locations and extension opportunities (comprised of 191 locations in the onshore Gulf Coast area and 675 locations in the Barnett Shale area). We believe our use of 3-D seismic surveys reduces, but does not eliminate, the risk of drilling.

Maintain a Balanced Exploration Drilling Portfolio. We seek to balance our drilling program between projects with relatively lower risk and moderate potential and drilling prospects that have relatively higher risk and substantial potential. We believe we have furthered this strategy through the expansion of the Barnett Shale operations in which our wells generally have longer-lived reserves and generally lower risk/lower reward than our average onshore Gulf Coast area wells. We will continue to expand our exploratory drilling portfolio, including lease acquisitions with exploration potential.

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 projects in order to better control drilling costs and the timing of drilling.

Retain and Incentivize a Highly Qualified Technical Staff. We employ 33 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 onshore Gulf Coast area, our exploration strategy has generally been to accumulate large amounts of 3-D seismic data along primarily prolific, producing trends after obtaining options to lease areas covered by the data. In the case of our Barnett Shale area, our exploration strategy has been to accumulate significant leasehold positions in the proximity of known or emerging pipeline infrastructures, followed by the acquisition and processing of 3-D seismic data. We use 3-D seismic data to identify or evaluate prospects before drilling the prospects that fit our risk/reward criteria. We typically seek to explore in locations within our areas of expertise that we believe have (1) longer-lived, reserve-proven trends, such as the Barnett Shale trend, (2) numerous accumulations of normally pressured reserves at shallow depths and in geologic traps that are difficult to define without the interpretation of 3-D seismic data or (3) the potential for large accumulations of deeper, over-pressured reserves.

As a result of the increased availability of economic onshore 3-D seismic surveys and the improvement and increased affordability of data interpretation technologies, we have relied almost exclusively on the interpretation of 3-D seismic data in our exploration strategy. We generally do not invest any substantial portion of the drilling costs for an exploration well without first interpreting 3-D seismic data. The principal advantage of 3-D seismic data over traditional 2-D seismic analysis is that it affords the geoscientist the ability to interpret a three dimensional cube of data as compared to interpreting between widely separated two dimensional vertical profiles. Consequently, the geoscientist is able to more fully and accurately evaluate prospective areas, improving the probability of drilling commercially successful wells in both exploratory and development drilling.

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.

Historically, we sought to obtain large volumes of 3-D seismic data by participating in large seismic data acquisition programs either alone or pursuant to joint venture arrangements with other energy companies, or through group shoots in which we shared the costs and results of seismic surveys. By participating in joint ventures and group shoots, we were able to share the up-front costs of seismic data acquisition and interpretation, thereby enabling us to participate in a larger number of projects and diversify exploration costs and risks. Most of our operations are conducted through joint operations with industry participants.

We have also participated in 3-D data licensing swaps, whereby we transfer license rights to certain proprietary 3-D data we own in exchange for license rights to other 3-D data within our areas, thus allowing us to obtain access to additional 3-D data within our onshore Gulf Coast area at either minimal or no out-of-pocket cash cost. Since 2001, we also have made significant purchases of 3-D data from the libraries of seismic companies at favorable pricing.

In more recent years, we have focused less on conducting proprietary 3-D surveys and have focused instead on (1) the continual interpretation and evaluation of our existing 3-D seismic database and the drilling of identified prospects on such acreage and (2) the acquisition of existing non-proprietary 3-D data at reduced prices, in many cases contiguous to or near existing project areas where we have extensive knowledge and subsequent acquisition of related acreage as we deem to be prospective based upon our interpretation of such 3-D data.

In late 2005, we entered an agreement that allows Carrizo to acquire approximately 800 square miles of 3-D seismic data in our onshore Gulf Coast area over a three year period. Specific operating areas to which new data were added as a result of the late 2005 data acquisition include 203 square miles of newly released 3-D data in south Louisiana, and 151 square miles of newly released 3-D data in Texas. These data acquisitions consist of existing nonproprietary data sets obtained from seismic companies at what we believe to be attractive pricing.

We also entered into a 3-D seismic data acquisition program in 2004 through 2006 to complete seismic shoots over significant acreage positions in our Barnett Shale area, covering an estimated 386 square miles.

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 projects along the Texas and Louisiana Gulf Coast. We believe that the experience of our management in the development, processing and analysis of 3-D projects and data in the onshore Gulf Coast area is a core competency to our continued success. Additionally, we believe that the experience we have gained in the Barnett Shale area, along with our extensive experience in fracturing and horizontal drilling technologies, will play a significant part in our future success.

We generally seek to obtain lease operator status and control over field operations, and in particular seek to control decisions regarding 3-D survey design parameters and drilling and completion methods. As of December 31, 2006, we operated 119 producing oil and natural gas wells. Although we initially did not act as operator for most of our projects in the Barnett Shale area, we now generally seek to control operations for most new exploration and development in that area, taking advantage of our technical staff experience in horizontal drilling and hydraulic fracturing.

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. We also seek to minimize cycle time from drilling to hook-up of wells, thereby accelerating cash flow and improving ultimate project economics.

We seek to use advanced production techniques to exploit and expand our reserve base. Following the discovery of proved reserves, we typically continue to evaluate our producing properties through the use of 3-D seismic data to locate undrained fault blocks and identify new drilling prospects and perform further reserve analysis and geological field studies using computer aided exploration techniques. We have integrated our 3-D seismic data with reservoir characterization and management systems through the use of geophysical workstations which are compatible with industry standard reservoir simulation programs.

SIGNIFICANT PROJECT AREAS

This section is an explanation and detail of some of the relevant project groupings from our overall inventory of productive wells, seismic data and prospects. Our operations are focused primarily in the onshore Gulf Coast area extending from South Louisiana to South Texas and the Barnett Shale trend in North Texas. Our other areas of interest are in East Texas, the Rocky Mountains and the U.K. North Sea and other shale trends in West Texas/New Mexico, Mississippi/Alabama, Kentucky and Arkansas. The table below highlights our main areas of activity:

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	Productive Wells		3-D Seismic Data	Net Options/ Leased	Drilling Capital Expenditures	
	Gross	Net	(Sq. Miles)	Acres	2006	2007 Plan
					(In millions)	
Onshore Gulf Coast:						
Wilcox	29	8	2,278	12,976	$ 4.9	$ 4.0
Frio/Vicksburg	49	11	2,271	11,045	5.3	1.7
Southeast Texas	19	7	1,216	8,819	19.0	7.8
South Louisiana	5	2	2,154	5,580	6.6	11.2
Barnett Shale	98	59	386	86,752	100.5	108.2
East Texas	54	53	511	4,817	0.7	4.6
Rocky Mountain			473	14,373		
North Sea			1,346	28,584	2.3	2.9
Floyd Shale			18	136,637		2.5
Kentucky Shale				17,579		
Fayetteville Shale				15,127		
Woodford/Barnett Shale				70,468		
Other Areas			1,144	9,996	3.3	1.0
Total	254	140	11,797	422,753	$ 142.6	$ 143.9

Onshore Gulf Coast Area

For purposes of presentation, we divide our onshore Gulf Coast area into four main producing areas: Wilcox, Frio/Vicksburg, Southeast Texas and South Louisiana. Our onshore Gulf Coast area generally contains geologically complex natural gas objectives well-suited for drilling using 3-D seismic evaluation.

In our onshore Gulf Coast area, we have a total inventory of 106 leased exploratory drillsites, 55 of which are field extension wells based on initial drilling success. We are pursuing acreage on an additional 85 seismically defined prospects. We plan to spend approximately $24.7 million on drilling expenditures in 2007, comprised of approximately 15 wells (7.0 net). We also plan to spend $3.1 million to purchase and reprocess 3-D seismic surveys during 2007.

Texas Wilcox Areas

We have licenses for approximately 2,278 square miles of 3-D seismic data and 12,976 net acres of leasehold in the Wilcox trend in Texas. From January 1, 2003 through December 31, 2006, we drilled and completed 27 wells (8.8 net) on 30 attempts in this area. We incurred capital drilling expenditures of $4.9 million and drilled six wells (1.5 net) in the Texas Wilcox area in 2006 and expect to devote approximately $4.0 million to drill three gross wells (0.8 net) in this area in 2007. In the Wilcox area 43 exploratory drillsites have been leased, 30 of which are field extension wells based on results of initial drilling. We are pursuing acreage on an additional 38 seismically defined prospects.

Texas Frio/Vicksburg/Yegua Areas

This combined trend area sometimes overlaps but is generally closer to the Texas Gulf Coast than the Wilcox areas discussed above. In any particular target or prospect in this area, the Frio is the shallower formation, above the deeper Vicksburg and still deeper Yegua formations. We have licenses for a total of over 2,271 miles of 3-D seismic data and 11,045 net leasehold acres over this trend. Our current focus is primarily in Brooks County, the location of the Encinitas Field.

We have an inventory of 14 leased exploratory drillsites in the Frio/Vicksburg trend, four of which are field extension wells based on success of initial drilling. We are pursing acreage on an additional 19 seismically defined prospects.

From January 1, 2003 through December 31, 2006, we drilled and completed 38.0 wells (9.0 net) in 42 attempts in this trend. We incurred capital drilling expenditures of $5.3 million and drilled two wells (0.6 net) in the Frio/Vicksburg trend area in 2006 and expect to devote approximately $1.7 million to drill three wells (0.9 net) in this area in 2007.

Southeast Texas Areas

The Southeast Texas area contains similar objective levels found in the Frio/Vicksburg/Yegua trend area. We separate this as

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a focus area because of the geographic concentration of our 3-D seismic data and because reservoirs in this area usually display seismic amplitude anomalies. Seismic amplitude anomalies can be interpreted as an indicator of hydrocarbons, although these anomalies are not necessarily reliable as to hydrocarbon presence or productivity. We have acquired licenses for approximately 1,216 square miles of 3-D data over our Southeast Texas project area which is focused primarily on the Frio, Yegua, Cook Mountain and Vicksburg formations.

We have 25 leased exploratory drillsites, seven of which are dependent on success of the other wells. An additional six prospects have been seismically mapped on which we are currently pursuing acreage.

From January 1, 2003 to December 31, 2006, we participated in the drilling and completion of 19 wells (6.7 net) in 23 attempts in this area. We incurred capital drilling expenditures of $19.0 million and drilled seven wells (2.6 net) in the Southeast Texas area in 2006 and expect to devote approximately $7.8 million and drill 5.0 gross wells in this area in 2007. The Liberty Project Area and Cedar Point Project Area have proven to be successful for us, and we expect that the Liberty Project Area will constitute a significant portion of our drilling program for 2007.

Liberty Project Area

We have identified and leased prospects including the Frio, Yegua, Cook Mountain, and Wilcox formations within the 705 square miles of 3-D seismic data in the Liberty Project Area which now covers significant areas of Liberty, Harris, and Hardin Counties, Texas.

As of December 31, 2006, we had identified 21 leased exploratory drilling locations and an additional six potential locations that we are attempting to lease in the Liberty Project Area. Ten of the total 21 prospects were generated from our 2006 seismic survey project. Carrizo s 2007 drilling plan provides for drilling two of these exploratory locations. Accordingly, we expect to continue significant drilling activity in the Liberty Project area in 2007.

South Louisiana Area

The South Louisiana area primarily contains objectives in the Middle and Lower Miocene intervals. We have acquired licenses for 2,154 square miles of 3-D data and approximately 5,580 net acres of leasehold. The 3-D seismic data sets are concentrated in one general area including St. Mary, Terrebonne and LaFourche Parishes.

Our South Louisiana inventory consists of 14 leased exploratory drillsites, seven of which are dependent on the success of the other wells. Carrizo is currently pursuing acreage on an additional 17 seismically defined prospects. From January 1, 2003 to December 31, 2006, we drilled and completed six wells (2.1 net) on eleven attempts in this area. We incurred capital drilling expenditures of $6.6 million and drilled three wells (1.1 net) in the South Louisiana area in 2006 and expect to devote approximately $11.2 million to drill 4.0 gross wells in this area in 2007.

Barnett Shale Trend

We began active participation in the Barnett Shale play in the Fort Worth Basin on acreage located west of the city of Fort Worth, Texas in mid-2003. In 2003, we acquired leases on approximately 4,100 net acres and invested $0.9 million to drill six wells (2.6 net), two of which were completed and producing and four of which were awaiting pipeline hookup at year end. Net production from the two online wells (0.6 net) was a combined 380 Mcfe per day at year end 2003.

In February 2004 we purchased specified wells and leases in the Barnett Shale trend in Denton County, Texas from a private company for $8.2 million. These non-operated properties have an average 39 percent working interest. The acquisition included 21 existing gross wells (6.7 net) and interests in approximately 1,500 net acres. Production at year end 2004 was approximately 2,800 Mcfe/d.

In April 2005 we acquired 600 net acres and working interests in 14 existing wells (7.3 net) with an estimated 5.4 MMcfe of proved reserves in the Barnett Shale trend for $2.3 million in cash and 112,697 shares of our common stock. In 2005, we drilled 37 additional wells (22.1 net) and acquired an additional 49,632 net acres.

During 2006, we drilled 46.0 additional wells (33.9 net) and acquired an additional 6,400 net acres, increasing our acreage at the end of 2006 to 86,752 net acres (primarily in Tarrant, Parker, Denton, Johnson, Hill and Erath counties). Carrizo was operator on 32 of the gross wells drilled. At year end 2006, 31 of the gross wells were producing and the remaining 15 wells were awaiting completion and/or pipeline connection.

We are continuing to expand our leasehold acquisition in this trend. Production at the end of 2006 and at March 20, 2007 was

approximately 19 MMcfe/d and 21 MMcfe/d, respectively. Net proved reserves have grown by 79% from 82.1 Bcfe on December 31, 2005 to 146.6 Bcfe on December 31, 2006. We are drilling in this trend with four Carrizo operated rigs as of March 20, 2007.

East Texas Area

The East Texas area encompasses multiple objectives, including the Wilcox and Cotton Valley intervals. We are focused on the Camp Hill Field, a Wilcox steam flood project in Anderson County, and the Tortuga Grande Prospect, a Cotton Valley sand opportunity. We have licenses for over 511 square miles of 3-D seismic data in the East Texas area and 4,817 net acres under lease.

We expect to invest $4.6 million to drill 27 gross wells in this region in 2007.

Camp Hill Project. We own interests in approximately 750 gross acres in the Camp Hill Field in Anderson County, Texas. We currently operate all of these leases. During the year ended December 31, 2006, the project produced an average of 40.9 Bbls/d of 19 API gravity oil. The wells produce from a depth of 500 feet and have utilized and plan to 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, 2006 averaged $68.99 per barrel ($11.50 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 Koch WTI during the year ended December 31, 2006) due to its suitability as a lube oil feedstock.

As of December 31, 2006, we had 6.2 MMBbls of proved oil reserves in this project, with 0.8 MMBbls of oil reserves currently developed. The proved undeveloped reserves at the Camp Hill Field constitute 16% of our proved reserves and account for 23% of our present value of net future revenues from proved reserves as of December 31, 2006. We have an average working interest of approximately 92.1% in this field and an approximate net revenue interest of 71.0%.

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 have 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 a current 49.8% recovery efficiency as of December 31, 2006 and is currently still producing.

Although in 2006 and 2005 we increased our development activities in the Camp Hill Field, 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 and later, Barnett Shale areas 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. We performed remedial work on the existing wells and steam generators and began injecting steam in March 1994. From 1994 through 1998 and during the first nine months of 2000, we injected steam in 31 patterns. In the fourth quarter of 2000, we suspended steam injection in response to high fuel gas prices and to pursue a lower steam cost solution through our cogeneration negotiations. Thereafter, we drilled one well in 2001, seven wells in 2005 and ten wells (including six injection wells) in 2006.

The most important reason for our delay in both resuming steam injection and moving to full development was the potential for significantly improved profitability that would result from the construction of a nearby cogeneration plant. Cogeneration plants typically provided 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 $91 million in steam costs compared to

$18.8 million for drilling and development capital that is needed to fully develop the proved undeveloped reserves in this field. Previously, our management believed that the demand for electricity in the East Texas area would increase in the future such that it would become lucrative for us or a third party to build a cogeneration plant in the area. In this cogeneration plant, a gas turbine would be used to generate electricity, and the waste heat would be used to produce steam. The steam would be captured for injection in the Camp Hill Field, while the electricity would be sold into the Texas electric power grid. In 2000, we engaged in discussions with another party regarding the building of a cogeneration facility, but we ultimately did not reach acceptable terms with that party. We subsequently continued to explore the possibility of a cogeneration facility in the Camp Hill Field and worked with electricity industry consultants in 2002 and 2005.

During the time we were continuing to assess the relative attractiveness of building a cogeneration plant, and in light of relatively high fuel gas costs at that time, we pursued other exploration projects primarily along the onshore Gulf Coast and in the Barnett Shale, starting in 2003, that we believed offered us potentially higher rates of return. These other projects have been the primary focus of our operations over the last several years. Our timing of Camp Hill development has also been impacted by our leasing activities in the field by which we increased our working interest and net revenue interest in our leases in the field so that we would own a greater share of these properties when we later developed them. We believe that we were able to increase our interests on more favorable terms by deferring the full scale development of the field. The addition of working interests in the Camp Hill leases further improved the economics of the development of this field as well as favorably affect the development plan for the steam drive patterns in the field.

In 2006, we continued to invest the majority of our budgeted capital expenditures in our Barnett Shale and onshore Gulf Coast areas where the rates of return are traditionally higher and our leases expire sooner, which gives these projects greater immediacy. We did, however, drill four gross wells (four net) and six gross injection wells in the Camp Hill Field in 2006.

In mid-2005, we reengaged an electricity industry consultant with cogeneration experience to further investigate the feasibility of establishing a cogeneration plant in the area. After extensive discussions with the consultant, we concluded that there continues to be overcapacity of electricity in the regional market and that overcapacity is not likely to reverse itself in the near term and that the capital expenditures associated with building a cogeneration plant are not likely to be warranted for a period of several years. As a result, we determined that, rather than awaiting the construction of a cogeneration plant, we would instead further develop our Camp Hill properties with the existing steam generators.

In August 2005, management proposed the acceleration of the Camp Hill development to our board of directors. Accordingly, a development plan was formally approved by the board for increased drilling activity in the Camp Hill Field, beginning with an initial 60-well drilling program. In February 2006, our board of directors formally approved a multi-year plan to fully develop the entire Camp Hill Field. In furtherance of this plan, we expect to drill between 25 and 30 gross wells (25 to 30 net) in this area at an estimated cost of $2.3 million during 2007. To fully develop the field, we expect to drill approximately 317 wells from 2007 through 2018, at a total cost of approximately $18.8 million and total operating costs including steam of approximately $128.0 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.

We have taken other steps to increase Camp Hill development. To implement our development plan, we have entered into a new fuel gas supply contact; we are upgrading the steam generator burners and burner controls; and we have obtained a 30-well drilling rig contract. This rig was placed in the field in late March 2006. We recommenced steam injection in the Camp Hill Field in April 2006.

Other Project Areas in the East Texas Region

We have leased seven additional exploratory prospects in our East Texas region. We are shooting a 20 square mile 3-D survey to evaluate additional potential of the Tortuga Grande area. We expect to invest $2.3 million to drill two additional wells based on the integration of new data with the well information.

Wyoming/Montana Coalbed Methane Project Area

Rocky Mountain Region

In June 2003, we contributed our Powder River Basin interests, including all leasehold, wells and reserves, in the Arvada, Bobcat, Clearmont and Kirby prospects into the formation of Pinnacle. Our interests in Castle Rock, Montana and Oyster Ridge, Wyoming were retained. While no proved reserves have yet been booked in either area, drilling operations were conducted at both during 2005, with two and four wells, respectively, drilled in each area. At the end of 2006, we owned direct interests in 104,706 gross acres (including 23,784 acres which have now been optioned via drill-to-earn provisions of a farmout at Oyster Ridge).

At year-end 2006, Pinnacle had completed the acquisition and/or drilling of 883 gross wells, or approximately 535 net. As of December 31, 2006, Pinnacle owned natural gas and oil leasehold interests in approximately 454,000 gross (306,000 net) acres and had estimated net proved reserves of 20.3 Bcf.

Coalbed methane wells typically first produce water in a process called dewatering and then, as the water production declines, begin producing methane gas at an increasing rate. As the wells mature, the production peaks and begins declining. The dewatering process may require significant time and resources, and there can be no assurance that a well that encounters coal accumulations will in fact produce gas in commercial quantities. The ultimate commercial success of the well will depend upon several factors, including the establishment of gas and/or water inflow, the presence of pipelines and infrastructure, the satisfaction of engineering or production issues and other risks and uncertainties associated with drilling activities.

See Regulation Coalbed Methane Proceedings in Montana for a description of certain regulatory proceedings affecting coalbed methane drilling in Montana.

Other Project Areas

Floyd Shale

In 2005, we began activities in the Floyd Shale, a large shale play located in Alabama and Mississippi. At year end 2006, we had acquired approximately 136,500 net acres in this area. Based on our experience in the Barnett Shale and on preliminary geologic evaluation, in 2006 we decided to shoot 3-D seismic to evaluate our initial drilling locations. We had acquired and processed 18 square miles of 3-D seismic data at year end 2006. As in the Barnett Shale, our drilling program involves the drilling of both vertical and horizontal wells. We anticipate spending $2.5 million to drill one vertical well (0.5 net) and one horizontal well (0.5 net) in this region in 2007.

We have designed an evaluation program that will provide us with detailed information about the Floyd Shale project. Our plan is to drill a vertical well in which a core of the shale section will be taken. This core will be analyzed for all geothermal, geochemical, mineralogical, and mechanical properties. A horizontal well will be drilled immediately thereafter within one thousand feet of the vertical borehole. The vertical well will be used as a monitoring well to evaluate the effectiveness of the hydraulic fracing program in the horizontal well.

Fayetteville Shale and Woodford/Barnett Shale Plays

Carrizo identified several large shale resource plays in 2005 in the Fayetteville Shale (located in the Arkoma Basin of Arkansas), and the Delaware Basin Woodford/Barnett (West Texas/New Mexico) and Marfa Basin Barnett Shales (West Texas) (collectively, the Woodford/Barnett Shale). Detailed mapping of shale extent, depth, thickness, organic content, thermal maturation, as well as cost and availability of acquiring leases were analyzed to define the project fairways to lease. Carrizo has been successful in acquiring over 15,000 net acres in the Fayetteville Shale and over 70,000 net acres in the Woodford/Barnett Shale comprised of over 58,000 net acres in the Marfa Basin and about 12,100 net acres in the Delaware Basin.

U.K. North Sea Region

We were originally awarded seven acreage blocks in 2003, consisting of one Traditional and three Promote licenses, in the United Kingdom s 21st Round of Licensing. Subsequently, we generated a number of prospects from certain of these blocks and, accordingly, with a four year term, renewed the Promote license on two of these blocks in 2006. In 2006, all the Promote licenses were converted to Traditional licenses. As of December 31, 2006, we held licenses in five exploration blocks (totaling 124,000 gross acres), all located in mature producing areas of the Central and Southern North Sea in water depths of 30 to 350 feet. One of the Traditional licenses has a one well drilling commitment, with a four year term. The other Traditional licenses will be canceled after four years if we or our assignee elects not to commit to drill a well.

We believe that our U.K. North Sea interests are a natural extension of our business model to exploit resources in proven mature regions through 3-D seismic surveys, related technology and proper risk management. The U.K. North Sea includes proven hydrocarbon trends with established technological expertise, available large 3-D seismic datasets and significant exploration potential. On two of our licenses, we have promoted our interests to other parties experienced in drilling and operating in this region, leaving us with a carried interest on the initial exploration wells.

The first of two early prospects, in which we retain a 25% carried nonoperating working interest through casing point and a 3% overriding royalty, was drilled in late 2006 in the Southern North Sea. We subsequently participated in the test phase of this apparent gas discovery, and the well was suspended in late 2006 and currently is being studied for commercial viability by the operator. The second prospect, in which we retain a 15% carried nonoperating working interest through casing point and a 3% overriding royalty, is expected to be drilled in the second quarter of 2007 in the Central North Sea.

From the inception of our activity in this region in early 2003 through year end 2006, we have incurred approximately $1.7 million in total project costs, net of partner reimbursements, in the effort to maximize the value of our retained interests in this area. Our estimated firm project commitments for 2007 are approximately $0.1 million, largely for new acreage acquisition, data processing and, prospect generation, excluding contingent well test costs that may be associated with future drilling success.

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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, 2006. The reserve data and the present value as of December 31, 2006 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, 2006, 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)	1,638	5,557	7,195
Natural gas (MMcf)	73,912	92,886	166,798
Total proved reserves (MMcfe)	83,740	126,230	209,970
PV-10 Value(1)(2)	$230,754	$156,425	$387,179

(1) The PV-10 value as of December 31, 2006 is pre-tax and was

determined by using the December 31, 2006 sales prices, which averaged $54.73 per Bbl of oil, $5.77 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 $202.7 and $88.5 million, respectively. Accordingly,

the after-tax PV-10 value of Total Proved Reserves (or Standardized Measure of Discounted Future Net Cash Flows) is $298.7 million.

No estimates of proved reserves comparable to those included herein have been included in reports to any federal agency other than the Securities and Exchange Commission (the Commission). The reserve data set forth in this Annual Report on Form 10-K represent only estimates. See Management s Discussion and Analysis of Financial Condition and Results of Operations 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 Management s Discussion and Analysis of Financial Condition and Results of Operations 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 Management s Discussion and Analysis of Financial Condition and Results of Operations Risk Factors We cannot control the activities on properties we do not operate and are unable to ensure their proper operation and profitability.

In accordance with SEC regulations, 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, 2006, 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, 2006. 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 70% of our proved reserves for the year ended December 31, 2006, which reserves were located on our Barnett Shale properties. Fairchild & Wells, Inc. determined 18% of our proved reserves for the year ended December 31, 2006, which reserves were located on our properties in the Camp Hill Field. Ryder Scott Company Petroleum Engineers determined 12% of our proved reserves for the year ended December 31, 2006, 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 of 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 varied from 25.0% in 2006, to 19.1% in 2005 and to 17.2% in 2004. Set forth below is our reserve replacement ratio for the years ended December 31, 2006, 2005 and 2004.

	2006	2005	2004
Reserve Replacement Ratio	607%	530%	568%

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,		
	2006	2005	2004
Production volumes			
Oil (MBbls)	255	234	309
Natural gas (MMcf)	10,176	8,206	6,462
Natural gas equivalent (MMcfe)	11,705	9,612	8,319
Average sales prices			
Oil (per Bbl)	$ 63.62	$ 56.36	$ 41.00
Natural gas (per Mcf)	6.56	7.90	6.14
Natural gas equivalent (per Mcfe)	7.09	8.13	6.30
Average costs (per Mcfe)			
Camp Hill operating expenses	$ 11.50	$ 4.57	$ 3.31
Other operating expenses	1.33	0.62	0.59
Total operating expenses[1]	1.40	1.09	1.01

[1] Includes direct lifting costs (labor, repairs and maintenance, materials and supplies), workover 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 $10.0 million, $5.8 million and $2.9 million for the years ended December 31, 2006, 2005 and 2004, respectively. We have also included capitalized overhead in our finding cost of $3.5 million, $2.1 million and $1.7 million for the years ended December 31, 2006, 2005 and 2004, respectively. We have also included non-cash asset retirement obligations of $0.3 million, $1.8 million and $0.5 million for the years ended December 31, 2006, 2005 and 2004, respectively.

	Year Ended December 31,		
	2006	2005	2004
	(In thousands)		
Acquisition costs:			

Other unproved properties	$ 48,409	$ 49,089	$ 21,831
Proved properties		1,954	8,357
Exploration	104,473	50,303	39,181
Development	37,889	20,883	12,697
Asset retirement obligation	299	1,820	529
Total costs incurred	$ 191,070	$ 124,049	$ 82,595
Total proved reserves added (Mmcfe)	71,066	50,929	47,294
Average all-sources finding cost (per Mcfe)	$ 2.69	$ 2.44	$ 1.75

For the three year period ended December 31, 2006, our total adjusted costs for exploration, development and acquisition activities was approximately $397.7 million. Total exploration, development and acquisition activities for the three year period ended December 31, 2006 have added approximately 169.3 Bcfe of net proved reserves at an all-sources finding cost of $2.35 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 $31.4 million, $99.8 million and $39.8 million at December 31, 2006, 2005 and 2004, respectively, and includes total additions to proved undeveloped reserves of 28.4 Bcfe, 25.4 Bcfe and 27.6 Bcfe for the years ended December 31, 2006, 2005 and 2004, respectively. Accordingly, had we included future development costs in our computations, the average all-sources finding costs would have been $3.13, $4.39 and $2.59 per Mcfe for the years ended December 31, 2006, 2005 and 2004, respectively.

In order to maintain continued growth and 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,		
	2006	2005	2004
	(In thousands)		
Acquisition costs			
Unproved prospects	$ 48,409	$ 49,089	$ 21,831
Proved properties		1,954	8,357
Exploration	104,473	50,303	39,181
Development	37,889	20,883	12,697
Asset retirement obligation	299	1,820	529
Total costs incurred(1)	$ 191,070	$ 124,049	$ 82,595

(1) Excludes capitalized interest on unproved properties of $10.0 million, $5.8 million and $2.9 million for the years ended December 31,

2006, 2005 and 2004, respectively, and includes capitalized overhead of $3.5 million, $2.1 million and $1.7 million for the years ended December 31, 2006, 2005 and 2004, respectively. The table also includes non-cash asset retirement obligations of $0.3 million, $1.8 million and $0.5 million, respectively, for the years ended December 31, 2006, 2005 and 2004, respectively.

Drilling Activity

The following table sets forth our drilling activity for the years ended December 31, 2006, 2005 and 2004. 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. Our drilling activity from January 1, 1996 to December 31, 2006 has resulted in an apparent commercial success rate of approximately 79%.

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	Year Ended December 31,					
	2006		2005		2004	
	Gross	Net	Gross	Net	Gross	Net
Exploratory Wells						
Productive	47	26.9	38	20.6	39	14.9
Nonproductive	3	0.9	4	1.2	6	3.7
Total	50	27.8	42	21.8	45	18.6
Development Wells						
Productive	20	17.1	23	14.0	26	8.7
Nonproductive						
Total	20	17.1	23	14.0	26	8.7

The table excludes 12 gross (2.3 net) and six gross wells (1.1 net) drilled by CCBM during 2004 and 2005, respectively. The wells are in various stages of development and/or stages of production and are described in Wyoming/Montana Coalbed Methane Project Area above.

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, 2006. This table excludes all wells drilled or acquired by CCBM through 2003, a majority of which were contributed to Pinnacle in that year.

	Company Operated		Other		Total	
	Gross	Net	Gross	Net	Gross	Net
Oil	61.0	55.0	1.0	0.1	62.0	55.1
Natural gas	58.0	44.7	134.0	40.6	192.0	85.3
Total	119.0	99.7	135.0	40.7	254.0	140.4

Acreage Data

The following table sets forth certain information regarding our developed and undeveloped lease acreage as of December 31, 2006. Developed acres refers to acreage on which wells have been drilled or completed to a point that would permit production of oil and gas in commercial quantities. Undeveloped acreage refers to acreage on which wells have not been drilled or completed to a point that would permit production of oil and gas in commercial quantities whether or not the acreage contains proved reserves.

	Developed Acreage		Undeveloped Acreage		Total	
	Gross	Net	Gross	Net	Gross	Net
North Sea			124,242	28,584	124,242	28,584
Louisiana	2,318	745	5,903	4,835	8,221	5,580
Texas	55,111	22,963	265,353	165,399	320,464	188,362
Mississippi			228,643	136,637	228,643	136,637
Montana/Wyoming			80,922	8,427	80,922	8,427
Other			80,245	48,441	80,245	48,441
Total	57,429	23,708	785,308	392,323	842,737	416,031

The table does not include 1,800 gross and 776 net acres under lease option that we had a right to acquire in Texas and Louisiana, pursuant to various seismic and lease option agreements at December 31, 2006. 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 a period of three years. Further, the table does not include 23,784 gross and 5,946 net acres under lease option in Wyoming that CCBM has the right to earn pursuant to certain drilling obligations and other predetermined terms. We make certain statements in Business and Properties-General above regarding acreage that we are currently pursuing in various project areas. This acreage is not included in the table above. We have no rights in acreage that we are only pursuing because the acreage is not under lease or option and, in many cases, we are not in negotiations with respect to such acreage. Moreover, there can be no assurance that we will ever acquire such acreage.

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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 Texas and Louisiana onshore Gulf Coast area and the Barnett Shale 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 Management s Discussion and Analysis of Financial Condition and Results of Operations Critical Accounting Policies and Estimates Derivative Instruments and Hedging Activities, Qualitative and Quantitative Disclosures About Market Risk Derivative Instruments and Hedging Activities, and Item 1A. Risk Factors We may continue to hedge the price risks associated with our production. Our hedge transactions may result in our making cash payments or prevent us from benefiting to the fullest extent possible 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, 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 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.

Although we therefore 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

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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 under the provisions of the Energy Policy Act of 2005, the NGA has been amended 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 been directed to establish 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. The Energy Policy Act of 2005 also significantly increases the penalties for violations of the NGA to up to $1 million per day for each violation. There regularly are other 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, and despite the trend toward federal deregulation of the natural gas industry, whether or to what extent that trend will continue, or what the ultimate effect will be on our sales of gas, cannot be predicted.

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 these regulations or FERC proceedings, if any, on the transportation costs associated with oil production from our oil producing operations. We are not able at this time to predict the effects, if any, of these regulations on the transportation costs associated with oil production from our oil-producing operations.

Environmental Regulations

Our operations are subject to numerous 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 Management s Discussion and Analysis of Financial Condition and Results of Operations 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.

The U.S. Congress and various states are currently considering proposed legislation directed at reducing greenhouse gas emissions. It is not possible at this time to predict how legislation that may be enacted to address greenhouse gas emissions would impact the oil and gas exploration and production business. However, future federal laws and regulations, if enacted, could result in increased compliance costs or additional operating restrictions and adversely affect our business and prospects.

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 and local 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.

As further described in Significant Areas Other Areas of Interest Rocky Mountain Region, the issuance of new coalbed methane drilling permits and the continued viability of existing permits in Montana have been challenged in lawsuits filed in state and federal court.

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Coalbed Methane Proceedings in Montana

The issuance of new coalbed methane drilling permits in Montana was halted temporarily pending the Federal Bureau of Land Management s (BLM) approval of a final record of decision on Montana s Resource Management Plan environmental impact statement and the Montana Department of Environmental Quality s approval of a statewide oil and gas environmental impact statement. These two program approvals were obtained in April and August of 2003, respectively. Environmental groups initiated six lawsuits, challenging these program approvals. On February 25, 2005, the Federal District Court for the District of Montana issued an opinion in *Northern Plains Resource Council v. BLM* and a companion case vacating BLM s approval of the state plan and remanding the plan to BLM for further consideration. The Court further entered an order limiting the issuance of federal drilling permits to 500 per year and placed additional restrictions on certain operations. Various parties appealed these orders to the Ninth Circuit Court of Appeals. On May 31, 2005, the Ninth Circuit entered an order halting the issuance of any new permits pending their review of the parties various appeals. Oral argument was held in the case on September 15, 2005, and no decision has yet been issued. On February 2, 2007, in response to the orders issued by the Federal District Court for the District of Montana, BLM published the *Draft Supplement to the Montana Statewide Oil and Gas Environmental Impact Statement and Amendment to the Powder River and Billings Resource Management Plan* (SEIS). The draft SEIS attempts to address the Federal District Court s concerns. Public comments on the draft SEIS are due on May 2, 2007.

Although this decision could result in a continued suspension of the state s authority to issue new drilling permits or could effect the continued viability of existing permits in Montana, we believe that the decisions by the Federal Bureau of Land Management and the State of Montana ultimately will be upheld on appeal and/or BLM s reconsideration will address the Federal District Court s concerns and new coalbed methane development will continue to be authorized in Montana. There can be no assurance that any new permits will be obtained in a given time period or at all.

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 substantial percentage of our wells on a nonoperated basis, and may be accordingly limited in our ability to control the risks associated with natural gas and oil operations.

Title to Properties; Acquisition Risks

We believe we 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. Our revolving 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 more than 10% of its oil and natural gas revenues as follows:

	For the Year Ended December 31,		
	2006	2005	2004
WMJ Investments Corp.			12%
Cokinos Natural Gas Company			17%
Reichmann Petroleum	10%	11%	
Texon L.P.			13%
Chevron/Texaco	11%	12%	

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. See Note 2 of Notes to Consolidated Financial Statements for information regarding the bankruptcy of Reichmann Petroleum.

Employees

At December 31, 2006, we had 68 full-time employees, including six landmen, seven geoscientists and nine engineers. 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 testings. 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, the loss of, any of which could have a material adverse effect on our operations. We do not maintain key-man life insurance with respect to any of our employees.

Pinnacle Transaction

Formation and Operations

During the second quarter of 2003, we and Rocky Mountain Gas, Inc. (RMG) each contributed our interests in certain natural gas and oil leases in Wyoming and Montana in areas prospective for coalbed methane to a newly formed joint venture, Pinnacle Gas Resources, Inc. In exchange for the contribution of these assets, we each received 37.5% of the common stock of Pinnacle and options to purchase additional Pinnacle common stock, or on a fully diluted basis, we each received an ownership interest in Pinnacle of 26.9%. In March 2006 we entered into an agreement with Pinnacle and certain other shareholders of Pinnacle allowing us to exercise the Pinnacle stock options on a cashless, net exercise basis. At the end of 2005, we retained our interests in approximately 159,000 gross acres in the Castle Rock project area in Montana and the Oyster Ridge project area in Wyoming. We no longer have a drilling obligation in connection with the oil and natural gas leases contributed to Pinnacle. During 2004, we opted to exercise our right to cancel one-half of a remaining note payable to RMG, or approximately $300,000 in exchange for assigning one-half of our interest in the Oyster Ridge project area to RMG.

Simultaneously with the contribution of these assets, affiliates and related parties of CSFB Private Equity (CSFB) contributed approximately $17.6 million of cash to Pinnacle in return for redeemable preferred stock of Pinnacle, 25% of Pinnacle s common stock as of the closing date and warrants to purchase Pinnacle common stock. Our Chairman, Steven A. Webster, was Chairman of Global Energy Partners, Ltd., an affiliate of CSFB and is currently Chairman of Avista Capital Holdings, L.P., a private equity firm that makes investments in the energy sector and that has an affiliate that provides consulting services to an affiliate of CSFB.

In March 2004, the CSFB parties contributed additional funds of $11.8 million to continue funding the 2004 development program of Pinnacle.

In 2005, the CSFB Parties contributed $15.0 million to Pinnacle to finance an acquisition of additional undeveloped acreage. CCBM and U.S. Energy Corp. elected not to participate in the equity contribution. In November 2005, the CSFB Parties and a former Pinnacle employee received 30,000 and 2,000 shares of Pinnacle common stock, respectively, after exercising certain warrants and options.

In April 2006, prior to and in connection with a private placement by Pinnacle of 7,400,000 shares of its common stock, Pinnacle issued 25 new shares of its common stock to each of its stockholders in exchange for each existing share in a stock split; Pinnacle redeemed the preferred stock held by the CSFB Parties at 110% of par value; the CSFB Parties exercised all of their warrants on a cashless net exercise basis; and we and U.S. Energy exercised our respective options on a cashless net exercise basis. On April 11, 2006, after the stock split, the redemption of the preferred stock, the warrant and option exercises and the private placement, CCBM owned 2,459,102 shares of Pinnacle s common stock, and our ownership of Pinnacle was 9.5% on a fully diluted basis. On such date, U.S. Energy and the CSFB Parties owned 2,459,102 and 7,306,782 shares of Pinnacle s common stock, respectively, and their ownership of Pinnacle was 9.5% and 28.3% on a fully diluted basis, respectively. On September 22, 2006, U.S. Energy sold all of its 2,459,102 shares of Pinnacle s common stock to the CSFB Parties. At December 31, 2006, CCBM owned 2,459,102 shares of Pinnacle s common stock, and its ownership of Pinnacle was 9.5% on a fully diluted basis.

Immediately following its formation, Pinnacle acquired an approximate 50% working interest in existing leases and approximately 36,529 gross acres prospective for coalbed methane development in the Powder River Basin of Wyoming from an unaffiliated party for $6.2 million. As of December 31, 2006, Pinnacle owned natural gas and oil leasehold interests in approximately 454,000 gross (306,000 net) acres and had estimated net proved reserves of 20.3 Bcf.

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 Securities and Exchange 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

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 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 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, 2006, approximately 75% 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, 2006 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 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.

Natural gas and oil prices are highly volatile, and lower prices will negatively affect our financial results.

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;

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- 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.

Declines in natural gas and oil prices may materially adversely affect our financial condition, liquidity and ability to finance planned capital expenditures and results of operations.

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.

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We are subject to various governmental regulations and environmental risks.

Natural gas and oil operations are subject to various federal, state and local 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. Further, we or our affiliates hold certain mineral leases in the State of Montana that require coalbed methane drilling permits, the issuance of which has been challenged in pending litigation. We may not be able to obtain new permits in an optimal time period or at all. 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, a number of our wells in the Gulf Coast were shut in following Hurricanes Katrina and Rita in 2005. 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 and are unable to ensure their proper operation and profitability.

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. The success and timing of our drilling and development activities on properties operated by others therefore depend upon a number of factors outside of our control, including the operator s

- timing and amount of capital expenditures;
- expertise and financial resources;
- inclusion of other participants in drilling wells; and
- use of technology.

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. We generally deliver 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. 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

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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 each of S.P. Johnson IV, our President and Chief Executive Officer, Paul F. Boling, our Vice President and Chief Financial Officer, J. Bradley Fisher, our Vice President and Chief Operating Officer, Gregory E. Evans, our Vice President of Exploration and Richard H. Smith, our Vice President of Land. 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.

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 existing or new credit facilities may not be available in the future. Even if additional capital becomes available, it may not be on terms acceptable to us. Without additional capital resources, we may be forced to limit or defer our planned natural gas and oil exploration and development program and thereby adversely affect the recoverability and ultimate value of our natural gas and oil properties, in turn negatively affecting our business, financial condition and results of operations.

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.

Due to current industry demands, well service providers and related equipment and personnel are in short supply. This is causing escalating prices, delays in drilling and other exploration activities, the possibility of poor services coupled with potential damage to downhole reservoirs and personnel injuries. Such pressures will likely 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 over use of equipment and inexperienced personnel.

Our credit facilities contain operating restrictions and financial covenants, and we may have difficulty obtaining additional credit.

Over the past few years, increases in commodity prices and proved reserve amounts and the resulting increase in our estimated discounted future net revenue have allowed us to increase our available borrowing amounts. In the future, commodity prices may decline, we may increase our borrowings or our borrowing base may be adjusted downward, thereby reducing our borrowing capacity. Our credit facilities are secured by a pledge of substantially all of our producing natural gas and oil properties and assets, are guaranteed by our subsidiaries and contain 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 credit facilities also require that specified financial ratios be maintained. We may not be able to refinance our debt or obtain additional financing, particularly in view of the restrictions of our credit facilities on our ability to incur additional debt and the fact that substantially all of our assets are currently pledged to secure obligations under the credit facilities. The restrictions of our credit facilities 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 credit facilities 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.

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In addition, under the terms of our credit facilities, our borrowing base is subject to redeterminations at least quarterly 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 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 upon 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 Risk Factors Our reserve data and estimated discount future net cash flows are estimates based upon 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. See Management s Discussion and Analysis of Financial Condition and Results of Operations Critical Accounting Policies and Estimates for additional information on these matters.

We participate in oil and natural gas leases with third parties.

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 the joint activity obligations of the other working interest owners such as nonpayment of costs and liabilities arising from the actions of the working interest owners. In the event other working interest owners do not pay their share of such costs, we would likely have to pay those costs, which could materially adversely affect our financial condition.

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. As is customary in our industry, we 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. We, in some cases, perform curative work to correct deficiencies in the marketability 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.

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;

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- 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 faculties, 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.

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.

Normally pressured reservoirs. Reservoirs with a formation-fluid pressure equivalent to 0.465 psi per foot of depth from the surface. For example, if the formation pressure is 4,650 psi at 10,000 feet, then the pressure is considered to be normal.

Over-pressured reservoirs. Reservoirs subject to abnormally high pressure as a result of certain types of subsurface formations.

Petrophysical study. Study of rock and fluid properties based on well log and core analysis.

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 Securities and Exchange 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

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Name	Age	Position
S.P. Johnson IV	51	President, Chief Executive Officer and Director
Paul F. Boling	53	Chief Financial Officer, Vice President, Secretary and Treasurer
J. Bradley Fisher	46	Vice President and Chief Operating Officer
Gregory E. Evans	57	Vice President of Exploration
Richard H. Smith	49	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). Mr. Johnson is a Registered Petroleum Engineer and has a B.S. in Mechanical Engineering from the University of Colorado.

Paul F. Boling became our Chief Financial Officer, Vice President, Secretary and Treasurer in 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. Between 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.

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	High	Low
2006		
First Quarter	$ 29.70	$ 21.57
Second Quarter	32.95	24.99
Third Quarter	32.42	24.31
Fourth Quarter	33.94	23.08
2005		
First Quarter	17.58	9.93
Second Quarter	18.33	13.10
Third Quarter	31.63	16.93
Fourth Quarter	30.60	21.81

The closing market price of our common stock on March 1, 2007 was $30.12 per share. As of March 1, 2007, there were an estimated 113 record owners 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 credit facilities restrict our ability to pay dividends. See 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, 2001 to December 31, 2006, with the cumulative total return of the S&P 500 Index and the American Stock Exchange Natural Resources Industry Index of publicly traded companies over the same period. The graph assumes that $100 was invested on December 31, 2001 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 Securities and Exchange Commission. Shareholders are cautioned against drawing any conclusions from the date contained therein, as past results are not necessarily indicative of future financial performance.

	S&P	AMEX	COGI
December 31, 2001	$ 100	$ 100	$ 100
December 31, 2002	77	110	119
December 31, 2003	97	163	163
December 31, 2004	106	209	255
December 31, 2005	109	320	558
December 31, 2006	124	355	655

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

The following table presents information regarding the Company s purchases of its common stock on a monthly basis during the fourth quarter of 2006:

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Period	Total Number of Shares Purchased[(1)]	Average Price Paid Per Share	Total Number of Shares Purchased as Part of Publicly Announced Plans or Programs	Maximum Number (or Appropriate Dollar Value) of Shares that May Yet Be Purchased Under the Plan or Programs
October 2006	441	$ 29.20		
November 2006				
December 2006				
Total	441	$ 29.20		

(1) The 441 shares related to the surrender of shares of common stock to satisfy tax withholding obligations in connection with the vesting of restricted stock issued to employees under the Company s long-term incentive plan.

Item 6. Selected Financial Data

Our financial information set forth below for each of the five years in the period ended December 31, 2006, 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.

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	Year Ended December 31,				
	2006	2005	2004	2003	2002
	(In thousands, except per share data)				
Statement Of Operations Data:					
Oil and natural gas revenues	$ 82,945	$ 78,155	$ 52,397	$ 38,508	$ 26,802
Costs and expenses:					
Oil and natural gas operating expenses	16,428	10,437	8,392	6,724	4,908
Depreciation, depletion and amortization	31,129	21,374	15,464	11,868	10,574
General and administrative	14,909	11,243	8,255	5,952	4,049
Accretion expense related to asset retirement	496	70	23	41	
Total costs and expenses	62,962	43,124	32,134	24,585	19,531
Operating income	19,983	35,031	20,263	13,923	7,271
Net gain (loss) on derivatives	16,457	(5,882)	(625)		
Loss on extinguishment of debt	(294)	(3,721)			
Equity in loss of Pinnacle Gas Resources, Inc.	35	(2,542)	(1,399)	(830)	
Interest (expense) income, net of amounts capitalized and interest income	(8,127)	(4,295)	(622)	(19)	54
Other income and expenses, net	427	(457)	506	29	274
Income before income taxes	28,481	18,134	18,123	13,103	7,599
Income tax expense	10,233	7,500	7,009	5,063	2,809
Income before cumulative effect of change in accounting principle	18,248	10,634	11,114	8,040	4,790
Dividends and accretion of discount on preferred stock			350	741	588
Income available to common shareholders before cumulative effect of change in accounting principle	18,248	10,634	10,764	7,299	4,202
Cumulative effect of change in accounting principle				(128)	
Net income available to common shareholders	$ 18,248	$ 10,634	$ 10,764	$ 7,171	$ 4,202
Basic earnings per common share	$ 0.74	$ 0.45	$ 0.54	$ 0.50	$ 0.30
Diluted earnings per common share	$ 0.71	$ 0.44	$ 0.49	$ 0.43	$ 0.26
Basic weighted average shares outstanding	24,827	23,492	19,958	14,312	14,158
	25,565	24,361	21,818	16,744	16,148

Diluted weighted average shares outstanding					
Statements of Cash Flow Data:					
Net cash provided by operating activities	$ 65,437	$ 38,839	$ 32,501	$ 33,631	$ 18,572
Net cash used in investing activities	(161,576)	(111,417)	(80,294)	(29,673)	(22,747)
Net cash provided by (used in) financing activities	72,822	95,635	50,139	(5,379)	5,682
Other Operating Data:					
Capital expenditures	$ 201,773	$ 135,156	$ 83,891	$ 31,930	$ 23,343
Debt repayments (1)	40,536	101,021	13,737	5,951	8,745

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	2006	2005	As of December 31, 2004	2003	2002
			(In thousands)		
Balance Sheet Data:					
Working capital (deficit)	$ (17,014)	$ 10,307	$ (8,937)	$ (11,817)	$ (1,442)
Property and equipment, net	445,447	314,074	205,482	135,273	120,526
Total assets	494,795	383,101	234,345	156,803	135,388
Long-term debt, including current maturities	188,758	149,294	62,974	36,253	39,495
Convertible participating preferred stock				7,114	6,373
Total equity	212,274	155,385	121,060	76,072	66,816

(1) Debt repayments include amounts refinanced.

Forward Looking Statements. The statements contained in all parts of this document, (including any portion attached hereto) 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 oil and gas exploration, acquisition of 3-D seismic data (including number, timing and size of projects), planned evaluation of prospects, probability of prospects having oil and natural gas, 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 hiring, future exploration activity, production rates, potential drilling locations targeting coal seams, the outcome of legal challenges to new coalbed methane drilling permits in Montana, financing for our 2007 exploration and development program, 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, project, believe and simi 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 our dependence on our exploratory drilling activities, the volatility of oil and natural gas prices, the need to replace reserves depleted by production, operating risks of oil and natural gas operations, our dependence on our key personnel, factors that affect our ability to manage our growth and achieve our business strategy, risks relating to our limited operating history, technological changes, our significant capital requirements, the potential impact of government regulations, adverse regulatory determinations, including those related to coalbed methane drilling in Montana, litigation, competition, the uncertainty of reserve information and future net revenue estimates, property acquisition risks, industry partner issues, availability of equipment, weather and other factors detailed herein and in our other filings with the Securities and Exchange 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 duty to update any forward looking statement.

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

For the year ended December 31, 2006, we achieved record annual drilling success rates, levels of production, natural gas and oil revenues and at the end of 2006 our proved oil and gas reserves also reached a record level.

Due to our drilling success, we produced a record 11.7 Bcfe in 2006 compared to 9.6 Bcfe in 2005. At the end of 2006, we also reached a record estimated proved reserves level of 210.0 Bcfe with 71.1 Bcfe of net additions for the year, replacing 607% of our 2006 production. See Business and Properties - Natural Gas and Oil Reserve Replacement.

In 2006, we drilled 70 wells (44.9 net), including 19 wells in the onshore Gulf Coast area, 46 wells in the Barnett Shale play, one exploratory in the North Sea and four wells (excluding six injection wells) in the Camp Hill Field and other East Texas areas, with an apparent success rate of 95.7% compared to an apparent success rate of 94% in 2005, in which we drilled 65 wells (35.8 net). Between January 1, 2004 and December 31, 2006, 67% of our wells drilled were exploratory and 33% were developmental. In 2006, 72% of these wells were exploratory and 28% were developmental. The percentage of developmental wells reflects our increased activity in the Barnett Shale area, which has a relatively higher concentration of development well targets than the onshore Gulf Coast area.

In 2006, our natural gas and oil revenues reached a record level at $82.9 million, and our net income available to common shareholders was $18.2 million, or $0.74 and $0.71 per basic and fully diluted share, respectively. In 2005, our natural gas and oil revenues were $78.2 million, and our net income available to common shareholders was $10.6 million, or $0.45 and $0.44 per basic and fully diluted share, respectively. These increases in natural gas and oil revenues and net income were attributable in part to the record levels of production discussed above.

Our financial results are largely dependent on a number of factors, including commodity prices. Commodity prices are outside of our control and historically have been and are expected to remain volatile. Natural gas prices in particular have remained volatile during the last few years. Commodity prices are affected by changes in market demands, overall economic activity, weather, pipeline capacity constraints, inventory storage levels, basis differentials and other factors. As a result, we cannot accurately predict future natural gas, natural gas liquids and crude oil prices, and therefore, cannot accurately predict revenues. Carrizo s average natural gas sales price for 2006 decreased 17% to $6.55 per Mcf compared to $7.90 per Mcf in 2005, and the average oil sales price for 2006 increased 13% to $63.62 per barrel from $55.36 per barrel in 2005.

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 fluctuations associated with a portion of our natural gas and oil production and to achieve a more predictable cash flow. The use of these arrangements limits our ability to benefit from potential increases in the prices of natural gas and oil. Our derivative arrangements may apply to only a portion of our production and provide only partial protection against declines in natural gas and oil prices.

We have continued to reinvest a substantial portion of our operating cash flows into funding our drilling program and increasing the amount of 3-D seismic data available to us. In 2007, we expect capital expenditures, excluding capitalized interest and overhead, to be approximately $165.0 to $175.0 million, as compared to $188.3 million in 2006.

In 2007, we plan to drill 15 gross wells in the onshore Gulf Coast area, 53 gross wells in our Barnett Shale area, 25 to 30 gross wells in our East Texas area, primarily in our Camp Hill oil field, and five wells in other areas. The actual number of wells drilled will vary depending upon various factors, including the availability and cost of drilling rigs, land and industry partner issues, our cash flow, success of drilling programs, weather delays and other factors. If we drill the number of wells we have budgeted for 2007, depreciation, depletion and amortization, oil and natural gas operating expenses and production are expected to increase over levels incurred in 2006. Our ability to drill this number of wells is heavily dependent upon the timely access to oilfield services, particularly drilling rigs. The shortage of available rigs in 2006 delayed the drilling of several wells, slowing our growth in production.

At December 31, 2006, our net debt-to-total net capitalization ratio (computed as total debt net of cash, net debt , divided by the sum of (1) net debt plus (2) total book equity) was 46%, an increase from the 44% ratio at the end of 2005. This increase was primarily the result of borrowings under our Senior Secured Revolving Credit Facility totaling $41 million during 2006, partially offset by $33.5 million of net proceeds from the private placement of 1.35 million shares of common stock in July 2006. Please read Liquidity and Capital Resources Financing Arrangements for more information on our financing activities.

Since our initial public offering, we have grown primarily through the exploration of properties within our project areas, although we consider acquisitions from time to time and may in the future complete acquisitions that we find attractive. In 2004, 2005 and 2006 we completed asset acquisitions in our Barnett Shale project area described below in Barnett Shale Area.

2004 Public Offering and 2005 and 2006 Private Placements of Common Stock

In the first quarter of 2004, we completed the public offering of 6,485,000 shares of our common stock at $7.00 per share. The offering included 3,655,500 newly issued shares offered by us and 2,829,500 shares offered by certain selling shareholders. Our net proceeds of approximately $23.4 million from this offering were used: (1) to accelerate our drilling program, (2) to retain larger interests in portions of our drilling prospects that we otherwise would sell down (or for which we would seek joint partners), (3) to fund a portion of our activities in the Barnett Shale area and (4) for general corporate purposes. We did not receive any proceeds from the shares sold by the selling shareholders.

In the second quarter of 2005, we sold 1.2 million shares of our common stock (or approximately 5% of the fully diluted shares outstanding before the offering) to institutional investors at a price of $15.25 per share in a private placement (the 2005

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Private Placement), a 4.7% discount to the close price on the Nasdaq stock market for our common stock the day prior to pricing. The net proceeds from the 2005 Private Placement, after the placement agents fees but before offering expenses, were approximately $17.0 million. We used the proceeds from the 2005 Private Placement to fund a portion of our 2005 capital expenditure program, including our drilling programs in the Barnett Shale and onshore Gulf Coast areas.

In July 2006, we sold 1.35 million 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 number of shares sold was approximately 5.4% of our 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 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 SEC. 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.

Barnett Shale Area

In mid-2003, we became active in the Barnett Shale play located in Tarrant and Parker counties in Northeast Texas. Our activity accelerated as a result of the acquisition on February 27, 2004 of working interests and acreage in certain oil and gas wells located in the Newark East Field in Denton County, Texas in the Barnett Shale trend for $8.2 million (the Barnett Shale Acquisition). This acquisition included non-operated working interests in properties ranging from 12.5% to 45% over 3,800 gross acres, or an average working interest of 39%. The acquisition included 21 existing gross wells (6.7 net) and interests in approximately 1,500 net acres.

In April 2005, we acquired leases and producing wells in the Barnett Shale for approximately $4.1 million which consisted of approximately 600 net acres and working interests in 14 existing gross wells (7.3 net) with an estimated 5.4 MMcfe of proved reserves, based upon our internal estimates. All of the interests in the wells acquired related to wells in which we already had an interest. The consideration paid for this acquisition was $2.3 million in cash and 112,697 shares of our common stock.

Initially, we financed our Barnett Shale activities with our available cash on hand. We subsequently financed a portion of our 2004 capital expenditure program for the Barnett Shale area with a portion of the funds from the October 2004 issuance of the 10% Senior Subordinated Secured Notes the 2005 Private Placement, the 2006 Private Placement and the Second Lien Credit Facility.

In the Barnett Shale area, we drilled 33 gross wells (13.7 net) in 2004, 37 gross wells (22.1 net) in 2005 and 46 gross wells (33.9 net) in 2006, all of which were successful. We plan to drill 53 gross wells (47 net) in this area in 2007. At the end of 2006 our net production had risen to approximately 19 MMcfe/d with 92 gross wells on line and another 15 gross wells in various stages of testing, completion and awaiting pipeline hookup. As of March 20, 2007, our estimated net production in this area was 21 MMcfe/d.

In addition to our drilling activity, we have continued to expand our Barnett Shale acreage position, growing our net leasehold acreage from approximately 80,300 to 86,752 acres, at the end of 2005 and 2006, respectively. Similarly, we have increased our estimated number of developmental locations from 58 to 71 horizontal locations, at the end of 2005 and 2006, respectively, and we have increased our estimated number of exploratory drilling locations (horizontal) in the Barnett Shale area from 432 to 609 locations, at the end of 2005 and 2006, respectively.

Pinnacle Gas Resources, Inc.

During the second quarter of 2001, we acquired interests in natural gas and oil leases in Wyoming and Montana in areas prospective for coalbed methane and subsequently began to drill wells on those leases. During the second quarter of 2003, we (through CCBM, our wholly-owned subsidiary) contributed our interests in certain of these leases to a newly formed company, Pinnacle Gas Resources, Inc. (Pinnacle). In exchange for this contribution, we received

37.5% of the common stock of Pinnacle and options to purchase additional Pinnacle common stock.

In March 2004, Credit Suisse First Boston Private Equity Entities (the CSFB Parties) contributed additional funds of $11.8 million into Pinnacle to fund its 2004 development program, which increased the CSFB Parties ownership to 66.7% on a fully diluted basis assuming we and U.S. Energy Corp. each elected not to exercise our available options.

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In 2005, the CSFB Parties contributed $15.0 million to Pinnacle to finance an acquisition of additional undeveloped acreage. CCBM and U.S. Energy Corp. elected not to participate in the equity contribution. In November 2005, the CSFB Parties and a former Pinnacle employee received 30,000 and 2,000 shares of Pinnacle common stock, respectively, after exercising certain warrants and options. Accordingly, CCBM s ownership in Pinnacle was 32.3% at December 31, 2005 (15.8% on a fully diluted basis).

In April 2006, prior to and in connection with a private placement by Pinnacle of 7,400,000 shares of its common stock, Pinnacle issued 25 new shares of its common stock to each of its stockholders in exchange for each existing share in a stock split; Pinnacle redeemed the preferred stock held by the CSFB Parties at 110% of par value; the CSFB Parties exercised all of their warrants on a cashless net exercise basis; and CCBM and U.S. Energy exercised their respective options on a cashless net exercise basis. On April 11, 2006, after the stock split, the redemption of the preferred stock, the warrant and option exercises and the private placement, CCBM owned 2,459,102 shares of Pinnacle s common stock, and its ownership of Pinnacle was 9.5% on a fully diluted basis. On such date, U.S. Energy and the CSFB Parties owned 2,459,102 and 7,306,782 shares of Pinnacle s common stock, respectively, and their ownership of Pinnacle was 9.5% and 28.3% on a fully diluted basis, respectively. On September 22, 2006, U.S. Energy sold all of its 2,459,102 shares of Pinnacle s common stock to the CSFB Parties.

As of December 31, 2006, CCBM owned 2,459,102 shares of Pinnacle s common stock, and its ownership of Pinnacle was 9.5% on a fully diluted basis.

In addition to our interest in Pinnacle, we have maintained interests in approximately 23,784 gross acres at the end of 2006 in the Castle Rock coalbed methane project area in Montana and the Oyster Ridge project area in Wyoming. See Business and Properties-Pinnacle Transaction for a description of this transaction. Our discussion of future drilling and capital expenditures does not reflect operations conducted through Pinnacle.

Derivative Transactions

Our financial results are largely dependent on a number of factors, including commodity prices. Commodity prices are outside of our control and historically have been and are expected to remain volatile. Natural gas prices in particular have remained volatile during the last few years and more recently oil prices have become volatile. Commodity prices are affected by changes in market demands, overall economic activity, weather, pipeline capacity constraints, inventory storage levels, basis differentials and other factors. As a result, we cannot accurately predict future natural gas, natural gas liquids and crude oil prices, and therefore, cannot accurately predict revenues.

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 fluctuations associated with a portion of our natural gas and oil production and 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 and provide only partial protection against declines in natural gas and oil prices.

Results of Operations

Year Ended December 31, 2006 Compared to the Year Ended December 31, 2005

Oil and natural gas revenues for 2006 increased 6% to $82.9 million from $78.2 million in 2005. Production volumes for oil and natural gas in 2006 increased 22% to 11.7 Bcfe from 9.6 Bcfe in 2005. Realized average natural gas sales price for 2006 decreased 17% to $6.55 per Mcf compared to $7.90 per Mcf in 2005, and the average oil sales price for 2006 increased 13% to $63.62 per barrel from $55.36 per barrel in 2005. The increase in natural gas production was primarily due to the production from the three Galloway Gas Unit wells and new wells in the Barnett Shale area. The gas production volume increases were partially offset by production declines from the Delta Farms #1 and the Beach House #1 wells.

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, 2006 and 2005:

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	December 31,		2006 Period Compared to 2005 Period	
	2006	2005	Increase (Decrease)	% Increase (Decrease)
Production volumes-				
Oil and condensate (Mbbls)	255	234	21	9%
Natural gas (MMcf)	10,176	8,206	1,970	24%
Average sales prices-(1)				
Oil and condensate (per Bbl)	$ 63.62	$ 56.36	$ 7.26	13%
Natural gas (per Mcf)	6.56	7.90	(1.34)	(17%)
Operating revenues (In thousands) -				
Oil and condensate	$ 16,217	$ 13,204	$ 3,013	23%
Natural gas	66,728	64,951	1,777	3%
Total	$ 82,945	$ 78,155	$ 4,790	6%

Oil and natural gas operating expenses for 2006 increased 57% to $16.4 million from $10.4 million in 2005. Oil and natural gas operating expenses increased primarily due to (i) increased production, (ii) increased well count of Barnett Shale wells, (iii) higher workover expenses, (iv) higher ad valorem taxes and (v) rising costs of oil field services. This was partially offset by a $0.6 million decrease in severance taxes due to lower average natural gas prices in 2006 and a lower effective severance tax rate for our Barnett Shale wells which qualify for high cost gas tax well credits.

Depreciation, depletion and amortization (DD&A) expense for 2006 increased 46% to $31.1 million from $21.4 million in 2005. This increase was primarily due to (1) an increase in production volumes and (2) an increase in the DD&A rate primarily due to additions to the proved property cost base.

General and administrative (G&A) expense for 2006 increased 33% to $14.9 million from $11.2 million for 2005. The increase in G&A was due primarily to (i) higher incentive compensation and base salary costs of $0.6 million, (ii) increased contract labor cost of $1.0 million to cover certain accounting staff vacancies and to support the continued phase-in of our new integrated software system, (iii) $0.2 million in higher audit fees primarily related to the Company s 2005 financial restatement for mark-to-market accounting derivatives and (iv) increased bad debt expenses of $1.5 million primarily due to an outside operator bankruptcy filing.

The net gain on derivatives was $16.5 million for the year ended December 31, 2006, comprised of (1) a $9.3 million of unrealized mark-to-market net gains on derivatives ($9.9 million gain on oil and gas derivatives and $0.6 million losses on interest rate swaps) and (2) a $7.2 million of net realized gains ($5.6 million gain from oil and gas derivatives, $1.0 million gain from interest rate swaps and $0.6 million gain from the sell down of the interest rate swap position as a result of an amendment to the Company s second lien credit facility in December 2006).

Interest expense and capitalized interest in 2006 were $19.1 million and ($10.0) million, respectively, as compared to $11.0 million and $(5.8) million in 2005. These increases were attributable to the debt refinancing in July 2005 and borrowings under the Company s Senior Secured Credit Facility beginning in May 2006.

Income taxes increased to $10.2 million in 2006 from $7.5 million in 2005 due to the increase in pre-tax income.

Year Ended December 31, 2005 Compared to the Year Ended December 31, 2004

Oil and natural gas revenues for 2005 increased 49% to $78.2 million from $52.4 million in 2004. Production volumes for natural gas in 2005 increased 27% to 8,206 MMcf from 6,462 MMcf in 2004. Realized average natural gas prices increased 29% to $7.90 per Mcf in 2005 from $6.14 per Mcf in 2004. Production volumes for oil in 2005 decreased 24% to 234 MBbls from 309 MBbls in 2004. The increase in natural gas production was primarily due to the commencement of production from the Galloway #1 and new wells in the Barnett Shale, Encinitas Project and

Peters Ranch areas. The gas production volume increases were partially offset by: (1) production declines from the Delta Farms #1 and the Beach House #1 wells, which were shut-in for workovers during the second and third quarters of 2005; (2) the temporary shut-in of a number of wells as a result of the Katrina and Rita hurricanes; and (3) the sale of the Shadyside #1 in the first quarter of 2005. The decrease in oil production volume was principally due to production declines from the aforementioned workovers, the hurricane related shut-ins, and a natural production decline for the Hankamer #1.

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, 2004 and 2005:

	December 31,		2005 Period Compared to 2004 Period	
	2005	2004	Increase (Decrease)	% Increase (Decrease)
Production volumes-				
Oil and condensate (Mbbls)	234	309	(75)	(24%)
Natural gas (MMcf)	8,206	6,462	1,744	27%
Average sales prices-(1)				
Oil and condensate (per Bbl)	$ 56.36	$ 41.00	$ 15.36	37%
Natural gas (per Mcf)	7.90	6.14	1.76	29%
Operating revenues (In thousands) -				
Oil and condensate	$ 13,204	$ 12,687	$ 517	4%
Natural gas	64,951	39,710	25,241	64%
Total	$ 78,155	$ 52,397	$ 25,758	49%

Oil and natural gas operating expenses for 2005 increased 24% to $10.4 million from $8.4 million in 2004. Oil and natural gas operating expenses increased primarily due to higher severance taxes of $1.5 million on higher commodity prices, while higher lifting costs of $0.5 million were attributable to the increased number of producing wells and in part due to higher ad valorem taxes. Operating expenses per equivalent unit in 2005 increased to $1.09 per Mcfe from $1.01 per Mcfe in 2004. The per unit cost increased primarily as a result of the higher costs noted above.

Depreciation, depletion and amortization (DD&A) expense for 2005 increased 38% to $21.4 million from $15.5 million in 2004. This increase was primarily due to (1) an increase in production volumes and (2) an increase in the DD&A rate attributable to the increased land, seismic and drilling costs added to the proved property cost base and to future development costs largely related to the significant increase in Barnett Shale wells.

General and administrative (G&A) expense for 2005 increased 36% to $11.2 million from $8.3 million for 2004. The increase in G&A was due primarily to higher salary (due to increased headcount and annual raises) and incentive compensation costs and in part due to $0.3 million of expenses related to an integrated software migration project. Stock based compensation in 2005 increased by $1.4 million to $2.5 million compared to 2004.

Mark-to-market loss on derivatives, net was $5.9 million in 2005 comprised of (1) $2.3 million of realized loss on net settled derivatives and (2) $3.6 million of net unrealized loss on the derivatives accounted for as non-designated derivatives. Mark-to-market gain (loss) of derivatives, net was $(0.6) million in 2004 comprised of (1) $1.0 million of realized loss on net settled derivates and (2) $0.4 million of net unrealized gain on the derivatives accounted for as fair value hedges.

We recorded a $2.5 million after tax charge, or $0.10 per fully diluted share, on our minority interest in Pinnacle for the ended year December 31, 2005. Of this charge, $0.9 million relates to a valuation allowance for federal income taxes and $1.0 million is for the mark-to-market loss on derivatives. It is likely that Pinnacle will continue to record a valuation allowance on the deferred federal tax benefit generated from the operating losses incurred during the early development stages of Pinnacle s coalbed methane project. Concurrently, we will record valuation allowances relative to our share of Pinnacle s financial results.

Interest income was $0.9 million for the year of 2005 compared to $0.1 million in the year of 2004. The increase is due to the significant increase in the average cash and cash equivalent balance outstanding in connection with the July 2005 debt refinancing and borrowings under the $150.0 million Second Lien Credit Facility.

Interest expense and capitalized interest in 2005 were $11.0 million and ($5.8) million, respectively, as compared to interest expense and capitalized interest of $3.6 million and ($2.9) million in 2004. These increases in 2005 are attributable to the aforementioned debt refinancing in July 2005.

Income taxes increased to $7.5 million in 2005 from $7.0 million in 2004 due to the increase in pre-tax income, including the valuation allowance for the equity in loss of Pinnacle Gas Resources, Inc.

Dividends and accretion of discount on preferred stock decreased to zero in 2005 from $0.4 million in 2004 as a result of the conversion of all of the Series B Preferred Stock into common stock during the second quarter of 2004.

Net income available to common shareholders for 2005 decreased to $10.6 million from $10.8 million in 2004 primarily as a result of the factors described above.

Liquidity and Capital Resources

During 2006, our capital expenditures of $163.5, net of $38.3 million in proceeds from property sales, exceeded our net cash flows provided by operating activities. For future capital expenditures, we expect to use cash on hand, cash generated by operating activities and available draws on the Senior Credit Facility to partially fund our planned drilling expenditures and fund leasehold costs and geological and geophysical costs on our exploration projects in 2007. We may need to seek other financing alternatives to fully fund our 2007 capital expenditures program, including possible debt or equity financings.

We may not be able to obtain financing needed in the future on terms that would be acceptable to us. If we cannot obtain adequate financing, we may be required to limit or defer our planned oil and natural gas exploration and development program, thereby adversely affecting the recoverability and ultimate value of our oil and natural gas properties.

Our primary sources of liquidity have included funds generated by operations, proceeds from the issuance of various securities, including our common stock, preferred stock and warrants (including our public offering in 2004 and our private placements in 2005 and 2006 of our common stock), and borrowings under our credit facilities. Our liquidity position has been enhanced by the availability of funds under the Senior Credit Facility, the borrowing base of which was increased to $65.0 million, effective November 8, 2006. In addition, we received net proceeds of $33.5 million from the 2006 Private Placement.

In December 2006, we completed an amendment to the Second Lien Credit Facility providing for $75.0 million of additional borrowings which was drawn on January 3, 2007. The Company used a portion of $72.1 million net proceeds to repay the $41.0 million of outstanding borrowings under the Senior Credit Facility. Accordingly, the amended and undrawn borrowing base availability on our Senior Credit Facility was $54.25 million (See Financing Arrangements-Senior Secured Revolving Credit Facility for further discussion).

We received $38.3 million in proceeds from property sales in 2006. The sales included properties in both our Gulf Coast and Barnett Shale areas. We may continue to sell properties to fund a portion of our capital expenditures program.

Cash flows provided by operating activities were $65.4 million, $38.8 million and $32.5 million for 2006, 2005 and 2004, respectively. The increase in cash flows provided by operations in 2006 as compared to 2005 was primarily due to higher oil and gas revenues generated from increased production. The increase in cash flows provided by operations in 2005 as compared to 2004 was primarily due to increased revenues attributable to increased production and higher commodity prices.

Estimated maturities of long-term debt are $1.5 million in each of the years 2007 through 2009 and the remainder in 2010. The following table sets forth estimates of our contractual obligations as of December 31, 2006:

	Payments Due by Year (In thousands)					
	Total	**2007**	**2008**	**2009**	**2010**	**2011**
Long-term Debt	$ 188,758	$ 1,508	$ 1,500	$ 1,500	$ 184,250	$
Operating Leases	5,142	959	980	999	1,102	1,102
Drilling Contracts	12,253	12,253				
Seismic Data Commitments	375	375				
Total Contractual Cash Obligations	$ 206,528	$ 15,095	$ 2,480	$ 2,499	$ 185,352	$ 1,102

In addition to the contractual obligations presented above, we are also party to a firm well commitment agreement in the North Sea to drill one well within the next four years. Currently we expect to incur between $4 million and

$6 million to drill the well between 2007 and 2010; unless we alternately choose in the future to sell down our interest to another company.

We have planned capital expenditures (excluding capitalized interest) in 2007 of approximately $165.0 million to $175.0 million, of which $143.9 million is expected to be used for drilling activities in our project areas and the balance is expected to be used to fund 3-D seismic surveys and land acquisitions. In 2007, we plan to drill approximately 15 gross wells in the onshore Gulf Coast area and 53 gross wells in our Barnett Shale area and 25 to 30 gross wells in our East Texas areas, primarily in our Camp Hill oil field. The actual number of wells drilled and capital expended is dependent upon our available financing, cash

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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, as discussed below.

We have continued to reinvest a substantial portion of our cash flows into increasing our 3-D prospect portfolio, improving our 3-D seismic interpretation technology and funding our drilling program. Oil and gas capital expenditures were $191.1 million, $123.4 million and $83.9 million (including the Barnett Shale Acquisition) for 2006, 2005 and 2004, respectively. Our efforts resulted in the apparent drilling successes comprised of 70 gross wells in 2006, including 46 gross wells in the Barnett Shale area, 65 gross wells in 2005, including 37 gross wells in the Barnett Shale area, and 65 gross wells in 2004, including 33 gross wells in the Barnett Shale area.

We have increased the development of our Camp Hill project. In August 2005, management proposed the acceleration of the Camp Hill development to our board of directors. Accordingly, a development plan was formally approved by the board for increased drilling activity in the Camp Hill Field, beginning with an initial 60-well drilling program. In February 2006, our board of directors formally approved a multi-year plan to fully develop the entire Camp Hill Field. In furtherance of this plan, we expect to drill between 25 and 30 gross wells in this area at an estimated cost of $2.3 million during 2007. To fully develop the field, we expect to drill approximately 315 wells from 2007 through 2018, at a total cost of approximately $18.8 million and total operating costs including steam of approximately $128.0 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.

Off Balance Sheet Arrangements

We currently do not have any off balance sheet arrangements.

Financing Arrangements

First Lien Credit Facility

On September 30, 2004, we entered into a Second Amended and Restated Credit Agreement with Hibernia National Bank and Union Bank of California, N.A. (the First Lien Credit Facility), which was to mature on September 30, 2007. The First Lien Credit Facility provided for (1) a revolving line of credit of up to the lesser of the Facility A Borrowing Base and $75.0 million and (2) a term loan facility of up to the lesser of the Facility B Borrowing Base and $25.0 million (subject to the limit of the borrowing base, which was $22.5 million at March 31, 2006). It was secured by substantially all of our assets and was guaranteed by our subsidiary. On May 25, 2006, we terminated this agreement upon entering into the Senior Credit Facility as described below.

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 (the Agent) and the lenders party thereto (the Second Lien Credit Facility) that matures on July 21, 2010. The Second Lien Credit Facility provides for a term loan facility in an aggregate principal amount of $225.0 million. It is secured by substantially all of our assets and is guaranteed by our subsidiaries. The liens securing the Second Lien Credit Facility were second in priority to the liens securing the First Lien Credit Facility prior to its termination in May 2006, as discussed above, and are second in priority to the liens securing the Senior Credit Facility.

On December 20, 2006, the Company, entered into an amendment, effective as of December 19, 2006, to the Second Lien Credit Facility (the December 2006 Amendment). The amendment increased the principal amount available for borrowings under the Second Lien Credit Facility from $150 million to $225 million. The amendment also included the following, without limitation: (1) a reduction in the interest rate on each Eurodollar loan such that it is the adjusted LIBO rate plus a margin of 4.75%; (2) a reduction in the interest rate on each base rate loan such that it is (i) the greater of the Agent s prime rate and the federal funds effective rate plus 0.5%, plus (ii) a margin of 3.75%; (3) an adjustment to the minimum quarterly interest coverage ratio such that it is 2.75 to 1.0 through and including December 31, 2007 and 3.0 to 1.0 thereafter; (4) an adjustment to the minimum quarterly proved reserve coverage ratio such that it is 1.5 to 1.0 through December 31, 2007 and 2.0 to 1.0 thereafter; and (5) a maximum total net recourse debt to EBITDA ratio of not more than 3.75 to 1.0 through December 31, 2007 and 3.25 to 1.0 thereafter.

The interest rate on each base rate loan will be the greater of the Agent s prime rate and the federal funds effective rate plus 0.5%, plus a margin of 3.75%. The interest on each Eurodollar loan will be the adjusted LIBO rate plus a margin of 4.75%. Interest on Eurodollar loans is payable on either the last day of each period or every three months, whichever is earlier. Interest on base rate loans is payable quarterly. On December 31, 2006, the interest rate was approximately 10.11%, excluding the impact of interest rate swaps on the Company s outstanding borrowings under the Second Lien Credit Facility.

We are subject to certain covenants under the amended terms of the Second Lien Credit Facility. These covenants include, but are not limited to, the maintenance of the following financial covenants: (1) a minimum current ratio of 1.0 to 1.0 including availability under the borrowing base under the Senior Credit Facility; (2) a minimum quarterly interest coverage ratio of 2.75 to 1.0 through December 31, 2007 and 3.0 to 1.0 thereafter; (3) a minimum quarterly proved reserve coverage ratio of 1.5 to 1.0 through December 31, 2007 and 2.0 to 1.0 thereafter; and (4) a maximum total net recourse debt to EBITDA (as defined in the Second Lien Credit Facility) ratio of not more than 3.75 to 1.0 through December 31, 2007 and 3.25 to 1.0 thereafter.

The Second Lien Credit Facility also places restrictions on additional 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 Second Lien Credit Facility is subject to customary events of default. Subject to certain exceptions, if an event of default occurs and is continuing, the Agent may accelerate amounts due under the Second Lien Credit Facility (except for a bankruptcy event of default, in which case such amounts will automatically become due and payable). If an event of default occurs under the Second Lien Credit Facility as a result of an event of default under the Senior Credit Facility, the Agent may not accelerate the amounts due under the Second Lien Credit Facility until the earlier of 45 days after the occurrence of the event resulting in the default and acceleration of the loans under the Senior Credit Facility.

As of December 31, 2006, we had $147.8 million of borrowing outstanding under the Second Lien Credit Facility. In January 2007, the Company drew the additional $75.0 million in borrowings and received net proceeds of $72.1 million related to the December 2006 Amendment.

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 that matures on May 25, 2010. The Senior Credit Facility provides 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 assets and is guaranteed by our subsidiaries. The liens securing the Senior Credit Facility are first in priority to the liens securing the Second Lien Credit Facility.

As of December 31, 2006, we had $41.0 million of borrowings outstanding on a borrowing base availability of $65.0 million.

On December 20, 2006, the Company amended its Senior Credit Facility (the Senior Credit Amendment) in connection with the aforementioned December 2006 Amendment. On January 3, 2007, the Company drew the $75.0 million of additional borrowings from its Second Lien Credit Facility, using a portion of the net proceeds to repay the $41.0 million of outstanding borrowings under the Senior Credit Facility.

Following the repayment of the outstanding borrowings on January 3, 2007, the amended and undrawn borrowing base was $54.25 million, with a conforming borrowing base of $46.75 million and subject to monthly reductions of $1.69 million commencing May 1, 2007 and continuing on the first day of each month thereafter until the borrowing base is redetermined. We may request one unscheduled borrowing base determination subsequent to each scheduled determination, and the lenders may request unscheduled determinations at any time. In the event the outstanding principal balance of indebtedness under the Second Lien Credit Facility exceeds $225.0 million, the borrowing base under the Senior Credit Facility will be reduced $1.00 for every $4.00 of such additional indebtedness under the Second Lien Credit Facility.

If the outstanding principal balance of the revolving loans under the Senior Credit Facility exceeds the borrowing base at any time, we have the option within 30 days to take any of the following actions, either individually or in combination: make a lump sum payment curing the deficiency, pledge additional collateral sufficient in the lenders opinion to increase the borrowing base and cure the deficiency or begin making equal monthly principal payments that will cure the deficiency within the ensuing six-month period. Those payments would be in addition to any payments that may come due as a result of the quarterly borrowing base reductions. Otherwise, any unpaid principal or interest will be due at maturity.

The annual interest rate on each base rate borrowing will be (1) 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 (2) a margin between 0.25% and 1.75% (depending on the current level of borrowing base usage). The interest rate on each Eurodollar Loan will be the adjusted LIBOR Rate plus a margin between 1.5% to 3.0% (depending on the current level of borrowing base usage).

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 3.75 to 1.0 for the fiscal quarters through and including December 31, 2007, 3.25 to 1.0 for the fiscal quarter March 31, 2008 and thereafter. 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, 2006, one letter of credit totaling $500,000 was outstanding.

Lease Option Arrangements

Due to the limited capital available in the first half of 2006 to fund all of the Company s ongoing lease acquisition efforts in the Barnett Shale and other shale plays, the Company elected to enter into several lease option agreements with a number of third parties and with Steven A. Webster, the Company s chairman (collectively, the counterparties). The terms and conditions of the leasing arrangement (agreement terms are described below) with Mr. Webster are consistent with the leasing arrangements the Company has entered into with the other third parties. These leasing 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. Strategically, these leasing arrangements have allowed the Company to temporarily control important acreage positions during periods that the Company has lacked sufficient capital to directly acquire such oil and gas leases.

Since May 2006, the Company has acquired certain oil and gas leases through the aforementioned lease option arrangement with Mr. Webster. The acquisitions were made pursuant to a land option agreement between Mr. Webster and the Company dated January 25, 2006. The terms and conditions of this leasing arrangement with Mr. Webster are consistent with leasing arrangements the Company has entered into with the other third parties. Under the option agreement, Mr. Webster agreed to acquire oil and gas leases in areas where the Company is actively leasing or that it deems prospective. On or before the 90th day from the date that Mr. Webster acquires any lease in these areas, the Company has the option to acquire these leases from Mr. Webster for 110% of Mr. Webster s purchase price or, on the 90th day, pay a non-refundable 10% option extension fee to add a second 90-day option period. On or before the end of this second 90-day option period, the Company has the option to pay Mr. Webster 110% of his original purchase price to acquire the lease. If, at the end of the second option period, the Company has not exercised its purchase option, Mr. Webster will retain ownership of the oil and gas leases. In addition to the cash payments described above, the Company will assign a one-half of one percent of 8/8ths overriding royalty interest (proportionally reduced to the actual net interest in any given lease acquired) on any lease it acquires from Mr. Webster in the first 90-day option period and a one percent of 8/8ths overriding royalty interest (also proportionally reduced) on any lease acquired from Mr. Webster in the second 90-day option period. As of December 31, 2006, Mr. Webster has acquired oil and gas leases for approximately $4.2 million, the Company paid approximately $4.4 million for leases from Mr. Webster and the Company has made option extension payments of approximately $48,000 to Mr. Webster. There are currently no outstanding lease options under our arrangement with Mr. Webster. The Company may continue to use these arrangements as a strategic alternative.

Effects of Inflation and Changes in Price

Our results of operations and cash flows are affected by changing oil and natural gas prices. If the price of oil and natural gas increases (decreases), there could be a corresponding increase (decrease) in the operating cost that we are required to bear for operations, as well as an increase (decrease) in revenues. Inflation has had a minimal effect on us.

Recently Issued Accounting Pronouncements

In July 2006, the FASB issued FASB Interpretation No. 48, Accounting for Uncertainty in Income Taxes an Interpretation of FASB Statement 109 (FIN 48), which clarifies the accounting for uncertainty in tax positions taken or expected to be taken in a tax return, including issues relating to financial statement recognition and measurement. FIN 48 provides that the tax effects from an uncertain tax position can be recognized in the financial statements only if the position is more-likely-than-not of being sustained if the position were to be challenged by a taxing authority. The assessment of the tax position is based solely on the technical merits of the position, without regard to the likelihood that the tax position may be challenged. If an uncertain tax position meets the more-likely-than-not threshold, the largest amount of tax benefit that is greater than 50 percent likely of being recognized upon ultimate settlement with the taxing authority is recorded. The provisions of FIN 48 are effective for fiscal years beginning after December 15, 2006, with the cumulative effect of the change in accounting principle recorded as an adjustment to opening retained earnings. We are currently evaluating the impact of adopting FIN 48 on our consolidated financial statements.

In September 2006, the FASB issued SFAS No. 157, Fair Value Measurements. SFAS No. 157 defines fair value, establishes a framework for measuring fair value under generally accepted accounting principles and requires enhanced disclosures about fair value measurements. It does not require any new fair value measurements. SFAS No. 157 is effective for financial statements issued for fiscal years beginning after November 15, 2007 and interim periods within those fiscal years. We are currently assessing whether we will early adopt SFAS No. 157 as of the first quarter of fiscal 2007 as permitted, and are currently evaluating the impact adoption may have on our consolidated financial statements.

In September 2006, the FASB issued SFAS No. 158 Employers Accounting for Defined Benefit Pension and Other Postretirement Plans. This Statement amends Statement 87, FASB Statement No. 88, Employers Accounting for Settlements and Curtailments of Defined Benefit Pension Plans and for Termination Benefits, FASB Statement 106, and FASB Statement No. 132 (revised 2003), Employers Disclosures about Pensions and Other Postretirement Benefits, and other related accounting literature. SFAS No. 158 requires an employer to recognize the overfunded or underfunded status of a defined benefit postretirement plan (other than a multiemployer plan) as an asset or liability in its statement of financial position and to recognize changes in the funded status in the year in which the changes occur through comprehensive income. This statement also requires employers to measure the funded status of a plan as of the date of its year-end statement of financial position, with limited exceptions. Employers with publicly traded equity securities are required to initially recognize the funded status of a defined benefit postretirement plan and to provide the required disclosures as of the end of the fiscal year ending after December 15, 2006. We currently have no defined benefit or other postretirement plans subject to this standard.

In February 2007, the FASB issued SFAS No. 159, The Fair Value Option for Financial Assets and Financial Liabilities , which permits entities to choose to measure many financial instruments and certain other items at fair value. The objective is to improve financial reporting by providing entities with the opportunity to mitigate volatility in reported earnings caused by measuring related assets and liabilities differently without having to apply complex hedge accounting provisions. SFAS No. 159 applies to all entities and is effective for fiscal years beginning after November 15, 2007. We are currently determining the impact, if any, that SFAS No. 159 will have on our financial statements.

Recently Adopted Accounting Pronouncements

On December 16, 2004, the FASB issued SFAS No. 123 (revised 2004), Share-Based Payment (SFAS No. 123(R)). SFAS No. 123(R) requires companies to measure all employee stock-based compensation awards using a fair value method and record such expense in their consolidated financial statements. In addition, the adoption of SFAS No. 123(R) requires additional accounting and disclosure related to the income tax and cash flow effects resulting from share-based payment arrangements. SFAS No. 123(R) was effective beginning as of the first annual reporting period after June 15, 2005. We adopted the provisions of SFAS No. 123(R) during the first quarter of 2006 using the modified prospective method for transition and recognized approximately $0.5 million in stock-based compensation expense during 2006.

Summary of Critical Accounting Policies

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

Use of Estimates

The preparation of financial statements in conformity with U.S. generally accepted accounting principles requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities at the date of the financial statements and the reported amounts of revenues and expenses during the reporting periods. Actual results could differ from these estimates. The use of these estimates significantly affects our natural gas and oil properties through depletion and the full cost ceiling test, as discussed in more detail below.

Significant estimates include volumes of oil and natural gas reserves used in calculating depletion of proved oil and natural gas properties, future net revenues and abandonment obligations, impairment of undeveloped properties, future income taxes and related assets/liabilities, the collectability of outstanding accounts receivable, fair value of derivatives, stock-based compensation expense, contingencies and the results of future and current litigation. Oil and natural gas reserve estimates, which are the basis for unit-of-production depletion and the ceiling test, have numerous inherent uncertainties. The accuracy of any reserve estimate is a function of the quality of available data and of engineering and geological interpretation and judgment. Subsequent drilling results, testing and production may justify revision of such 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 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 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 for employees working directly on exploration activities of $3.5 million, $2.1 million and $1.7 million in 2006, 2005 and 2004 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 2006, 2005 and 2004 was $2.61, $2.22 and $1.86 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 reserves, 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 operations through depreciation, depletion and amortization.

In connection with our year-end 2006 ceiling test computation, a price sensitivity study also indicated that a 10 percent increase or decrease in commodity prices at December 31, 2006 would have increased or decreased the Full Cost Ceiling test cushion by approximately $40 million. The aforementioned price sensitivity is as of December 31, 2006 and, accordingly, does not include any potential changes in reserves due to first quarter 2007 performance, such as commodity prices, reserve revisions and drilling results.

The Full Cost Ceiling cushion at the end of 2006 of approximately $40.2 million was based upon average realized oil and natural gas prices of $54.73 per Bbl and $5.77 per Mcf, respectively, or a volume weighted average price of $38.75 per BOE. This cushion, however, would have been zero on such date at an estimated volume weighted average price of $34.91 per BOE. A BOE means one barrel of oil 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 been higher or substantially higher, more often for oil than natural gas on an energy equivalent basis, although there have been periods in which they have been lower or substantially lower.

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 and estimated future development costs 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 126.2 Bcfe, 97.9 Bcfe, and 72.5 Bcfe of proved undeveloped reserves, representing 60%, 65% and 66% of our total proved reserves at December 31, 2006, 2005 and 2004, respectively. As of December 31, 2006, 2005 and 2004, a portion of these proved undeveloped reserves, or approximately, 32.8 Bcfe, 38.1 Bcfe and 45.7 Bcfe, respectively, are attributable to our Camp Hill properties that we acquired in 1994. See Business and Properties East Texas Area Camp Hill Project 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 nondepleted 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 earnings by, (i) 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), (ii) an estimated $5.9 million in 2003 (due to higher depletion expense), (iii) an estimated $3.4 million in 2004 (due to higher depletion expense), (iv) an estimated $6.9 million in 2005 (due to higher depletion expense) and (v) an estimated $0.7 million in 2006 (due to higher depletion expense).

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, 2006 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 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 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 SEC requirements, we based the estimated discounted future net cash flows from proved reserves on prices and costs on the date of the estimate.

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 6.4% for the year ended December 31, 2006.

As of December 31, 2006, approximately 75% 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, 2006 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 nine 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

The Company uses derivatives, typically fixed-rate swaps and costless collars, to manage price and interest rate risk underlying our oil and gas production and the variable interest rate on the Second Lien Credit Facility. 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.

The Company s 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, 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 at December 31, 2005 and December 31, 2006 were treated as non-designated derivatives and the unrealized gain/(loss) related to the mark-to-market valuation was included in the Company s 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 lower prices will negatively affect our financial results.

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.

Total oil purchased and sold under swaps and collars during 2006, 2005 and 2004 were 82,200 Bbls, 108,500 Bbls and 121,700 Bbls, respectively. Total natural gas purchased and sold under swaps and collars in 2006, 2005 and 2004 were 5,171,000 MMBtu, 3,892,000 MMBtu and 3,936,000 MMBtu, respectively. The net gains (losses) realized by the Company under such derivative arrangements were $5.6 million, $(2.3) million and $(1.0) million for 2006, 2005 and 2004, respectively, and were included in net gain (loss) on derivatives.

As of December 31, 2006, 2005 and 2004 unrealized gains and (losses) on oil and gas derivatives of $9.9 million, $(4.2) million and $0.4 million, respectively, were included in net gain (loss) on derivatives.

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 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, 2006 we had the following outstanding derivative positions:

	Swaps		Collars		
Quarter	MMbtu	Average Fixed Price(1)	MMBtu	Average Floor Price(1)	Average Ceiling Price(1)
First Quarter 2007	1,257,000	$ 7.60	630,000	$ 7.95	$ 9.81
Second Quarter 2007	729,000	7.47	728,000	7.31	8.87
Third Quarter 2007	552,000	7.48	552,000	7.53	9.10
Fourth Quarter 2007	552,000	7.48	276,000	6.92	8.32
First Quarter 2008	273,000	7.94	546,000	7.32	8.95
Second Quarter 2008	273,000	7.94	364,000	7.35	9.10
Third Quarter 2008	276,000	7.94	368,000	7.35	9.10
Fourth Quarter 2008	276,000	7.94	368,000	7.35	9.10

(1) Based on Houston Ship Channel spot prices.

The table below summarizes our total production volumes subject to derivative transactions during 2006.

Natural Gas Swaps		**Natural Gas Collars**	
Volumes MMBtu	1,954,000	Volumes MMBtu	3,217,000
Average price $/MMBtu	$ 7.27	Average price $/MMBtu	
		Floor	$ 7.73
		Ceiling	$ 10.39

Crude Oil Collars	
Volumes Bbls	82,200
Average price $/Bbls	
Floor	$ 57.57
Ceiling	$ 69.52

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 gas production would have an approximate $8.3 million impact on our 2006 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. Net gains and (losses) realized by us related to these instruments were $5.6 million, $(2.3) million and $(1.0) million or $0.98, $(0.50) and $(0.21) per MMBtu for the years ended December 31, 2006, 2005 and 2004, respectively.

Interest Rate Risk. Our exposure to changes in interest rates results from our floating rate debt. The result of a 10% fluctuation in short-term interest rates would have impacted 2006 cash flow by approximately $1.8 million.

Financial Instruments and Debt Maturities. Our financial instruments consist of cash and cash equivalents, accounts receivable, accounts payable and bank borrowings, including borrowings under our Senior Credit Facility and Second Lien 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, 2006 and 2005, and were determined based upon interest rates currently available to us for borrowings with similar terms. Maturities of long-term debt are $1.5 million in each of the years 2007 through 2009 and the balance, or $184.3 million, is due in 2010.

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 Securities and Exchange Commission (SEC) under the Securities Exchange Act of 1934, as amended (the Exchange Act), is recorded, processed, summarized and reported within the time periods specified by the SEC s rules and forms, and that information is accumulated and communicated to our management, including our Chief Executive Officer and Chief Financial Officer, as appropriate to allow timely decisions regarding required disclosure.

In accordance with 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 SEC 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 as a result of the continued transition of newly hired accounting professionals in the second half of 2006 and the first quarter of 2007.

Pannell Kerr Forster of Texas, P.C. s audit report, dated March 30, 2007, expressed an unqualified opinion on our consolidated financial statements and its assessment of Management s Annual Report on Internal Control over Financial Reporting is included herein under paragraph (d).

(b) Management s Annual Report on Internal Control over Financial Reporting. Management, including the CEO and CFO, has the responsibility for establishing and maintaining adequate internal control over financial reporting, as defined in the Exchange Act, Rule 13a-15(f). 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 influenced 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 (GAAP). Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. In addition, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate or insufficient because of changes in operating conditions, or that the degree of compliance with the policies or procedures may deteriorate.

A control deficiency exists when the design or operation of a control does not allow management or employees, in the ordinary course of performing their assigned functions, to prevent or detect misstatements on a timely basis. A significant deficiency is a control deficiency, or combination of control deficiencies, that adversely affects the Company s ability to initiate, authorize, record, process, or report external financial data reliably in accordance with GAAP, such that there is a more than remote likelihood that a misstatement of the Company s annual or interim financial statements that is more than inconsequential will not be prevented or detected. A material weakness is a significant deficiency, or combination of significant deficiencies, that results in more than a remote likelihood that a material misstatement of the annual or interim financial statements will not be prevented or detected.

Management assessed internal control over financial reporting of the Company and subsidiaries as of December 31, 2006. The Company s management conducted its assessment in accordance with the *Internal Control Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). Management has concluded that the internal control over financial reporting was effective as of December 31, 2006.

Pannell Kerr Forster of Texas, P.C., the 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 internal control over financial reporting as of December 31, 2006, 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, 2006 that have materially affected, or are reasonably likely to materially affect, the Company s internal control over financial reporting.

(d) Report of Independent Registered Public Accounting Firm

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

We have audited management s assessment, included in the accompanying Management s Report on Internal Control over Financial Reporting, that Carrizo Oil & Gas, Inc. maintained effective internal control over financial reporting as of December 31, 2006, based on criteria established in *Internal Control Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO criteria). Carrizo Oil & Gas, Inc. s management is responsible for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting. Our responsibility is to express an opinion on management s assessment and an opinion on the effectiveness of 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, evaluating management s assessment, testing and evaluating the design and operating effectiveness of internal control, and performing such other procedures as we considered necessary in the circumstances. We believe that our audit provides a reasonable basis for our opinion.

A company s internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with 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 its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

In our opinion, management s assessment that Carrizo Oil & Gas, Inc. maintained effective internal control over financial reporting as of December 31, 2006, is fairly stated, in all material respects, based on the COSO criteria. Also in our opinion, Carrizo Oil & Gas, Inc., maintained, in all material respects, effective internal control over financial reporting as of December 31, 2006, based on the COSO criteria.

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the consolidated balance sheets of Carrizo Oil & Gas, Inc. as of December 31, 2006 and 2005 and the related consolidated statements of operations, shareholders equity, and cash flows for each of the three years in the period ended December 31, 2006

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and our report dated March 30, 2007 expressed an unqualified opinion thereon.

/S/ Pannell Kerr Forster of Texas,
P.C

Pannell Kerr Forster of Texas P.C.
Houston, Texas
March 30, 2007

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 information under the caption Proposal 1-Election of Directors and to the information under the caption Section 16(a) Reporting Delinquencies in our definitive Proxy Statement (the 2007 Proxy Statement) for our 2007 annual meeting of shareholders. The 2007 Proxy Statement will be filed with the Securities and Exchange Commission (the Commission) not later than 120 days subsequent to December 31, 2006.

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 2007 Proxy Statement, which will be filed with the Commission not later than 120 days subsequent to December 31, 2006.

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 2007 Proxy Statement, which will be filed with the Commission not later than 120 days subsequent to December 31, 2006.

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

The information required by this item is incorporated herein by reference to the 2007 Proxy Statement, which will be filed with the Commission not later than 120 days subsequent to December 31, 2006.

Item 14. Principal Accountant Fees and Services

The information required by this item is incorporated by reference to the 2007 Proxy Statement, which will be filed with the Commission not later than 120 days subsequent to December 31, 2006.

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.

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(a)(2) Financial Statement Schedules

SCHEDULE II
Carrizo Oil & Gas, Inc.
VALUATION AND QUALIFYING ACCOUNTS
Years Ended December 31, 2006, 2005 and 2004
(In thousands)

Description	Balance at Beginning of Period	Charged to Costs and Expenses	Deductions	Charged to Other Accounts	Balance at End of Period
2006					
Allowance for doubtful accounts	$ 253	$ 1,386(1)	$	$	$ 1,639
2005					
Allowance for doubtful accounts	325	(72)			253
2004					
Allowance for doubtful accounts		325			325

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

(a)(3) Exhibits

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	Amended and Restated Bylaws of the Company, as amended by Amendment No. 1 (incorporated herein by reference to Exhibit 3.2 to the Company s Registration Statement on Form 8-A (Registration No. 000-22915) Amendment No. 2 (incorporated herein by reference to Exhibit 3.2 to the Company s Current Report on Form 8-K dated December 15, 1999) and Amendment No. 3 (incorporated herein by reference to Exhibit 3.1 to the Company s Current Report on Form 8-K dated February 20, 2002).
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).
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

Exhibit Number	Description
	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).
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	Employment Agreement between the Company and Jack Bayless (incorporated herein by reference to Exhibit 10.5 to the Company s Current Report on Form 8-K filed on January 27, 2006).
10.26	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).
10.27	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).
10.28	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).
10.29	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).
10.30	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).
10.31	Employee Restricted Stock Award under the Incentive Plan of Carrizo Oil & Gas, Inc. granted to Jack Bayless effective January 23, 2006 (incorporated herein by reference to Exhibit 10.7 to the Company s Current Report on Form 8-K filed on January 27, 2006).
10.32	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).

Exhibit Number	Description
10.33	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).
10.34	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).
10.35	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)).
10.36	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)).
10.37	Amended and Restated Registration Rights Agreement dated December 15, 1999 among the Company, Paul B. Loyd Jr., Douglas A. P. Hamilton, Steven A. Webster, S.P. Johnson IV, Frank A. Wojtek and DAPHAM Partnership, L.P. (incorporated herein by reference to Exhibit 99.5 to the Company s Current Report on Form 8-K dated December 15, 1999).
10.38	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).
10.39	Purchase and Sale Agreement by and between Rocky Mountain Gas, Inc. and CCBM, Inc., dated June 29, 2001 (incorporated herein by reference to Exhibit 10.1 to the Company s Quarterly Report on Form 10-Q for the quarter ended June 30, 2001).
10.40	Contribution and Subscription Agreement dated June 23, 2003 by and among Pinnacle Gas Resources, Inc., CCBM, Inc., Rocky Mountain Gas, Inc. and the CSFB Parties listed therein (incorporated herein by reference to Exhibit 10.1 to the Company s Quarterly Report on Form 10-Q for the quarter ended June 30, 2003).
10.41	Amendment to Contribution and Subscription Agreement dated as of August 9, 2005 among Pinnacle Gas Resources, Inc., CCBM, Inc., U.S. Energy Corp., Crested Corp. and the CSFB Parties referred to therein (incorporated herein by reference to Exhibit 10.35 to the Annual Report on Form 10-K for the year ended December 31, 2005).
10.42	Second Amendment to Contribution and Subscription Agreement dated as of March 31, 2006 among Pinnacle Gas Resources, Inc., CCBM, Inc., U.S. Energy Corp., Crested Corp. and the CSFB Parties referred to therein (incorporated herein by reference to Exhibit 10.2 to the Company s Quarterly Report on Form 10-Q for the quarter ended March 31, 2006).

10.43	Second Amended and Restated Credit Agreement dated as of September 30, 2004 by and among Carrizo Oil & Gas, Inc., CCBM, Inc., Hibernia National Bank, as Agent, Union Bank of California, N.A., as co-agent, and Hibernia National Bank and Union Bank of California, N.A., as lenders (incorporated herein by reference to Exhibit 10.1 to the Company s Current Report on Form 8-K filed on October 6, 2004).
10.44	First Amendment to Second Amended and Restated Credit Agreement dated as of October 29, 2004 among Carrizo Oil & Gas, Inc., CCBM, Inc., Hibernia National Bank and Union Bank of California, N.A. (incorporated herein by reference to Exhibit 10.6 to the Company s Current Report on Form 8-K filed on November 3, 2004).
10.45	Commercial Guaranty made and entered into as of September 30, 2004 by CCBM, Inc. in favor of Hibernia National Bank, as agent (incorporated herein by reference to Exhibit 10.2 to the Company s Current Report on Form 8-K filed on October 6, 2004).
10.46	Amended and Restated Stock Pledge and Security Agreement dated and effective as of September 30, 2004 by Carrizo Oil & Gas, Inc. in favor of Hibernia National Bank, as agent (incorporated herein by reference to Exhibit 10.3 to the Company s Current Report on Form 8-K filed on October 6, 2004).
10.47	Second Amendment dated of as April 27, 2005 to the Second Amended and Restated Credit Agreement dated as of October 29, 2004 among Carrizo Oil & Gas, Inc. CCBM, Inc., Hibernia National Bank and Union Bank of California, N.A. (incorporated herein by reference to Exhibit 10.1 to the Company s Current Report on Form 8-K filed on May 3, 2005).
10.48	Third Amendment dated as of July 21, 2005 to the Second Amended and Restated Credit Agreement dated as of October 29, 2004 among Carrizo Oil & Gas, Inc., CCBM, Inc., Hibernia National Bank and Union Bank of California, N.A. (incorporated herein by reference to Exhibit 10.4 to the Company s Current Report on Form 8-K filed on July 22, 2005).
10.49	Second Lien Agreement dated as of July 21, 2005 among Carrizo Oil & Gas, Inc., CCBM, Inc., and the lenders named therein and Credit Suisse, as collateral agent and administrative agent (incorporated herein by reference to Exhibit 10.1 to the Company s Current Report on Form 8-K filed on July 22, 2005).

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Exhibit Number	Description
10.50	Stock Pledge and Security Agreement dated as of July 21, 2005 by Carrizo Oil & Gas, Inc. in favor of Credit Suisse, as collateral agent (incorporated herein by reference to Exhibit 10.2 to the Company s Current Report on Form 8-K filed on July 22, 2005).
10.51	Commercial Guaranty dated as of July 21, 2005 by CCBM, Inc. in favor of Credit Suisse (incorporated herein by reference to Exhibit 10.3 to the Company s Current Report on Form 8-K filed on July 22, 2005).
10.52	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).
10.53	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).
10.54	Form of Subscription and Registration Rights Agreement among the Company and the Subscribers named therein (incorporated herein by reference to Exhibit 10.5 to the Company s Quarterly Report on Form 10-Q for the quarter ended June 30, 2006).
10.55	Placement Agent Agreement dated July 25, 2006 between the Company and Johnson Rice & Company L.L.C. (incorporated herein by reference to Exhibit 10.6 to the Company s Quarterly Report on Form 10-Q for the quarter ended June 30, 2006).
10.56	Amendment No.1, effective as of December 19, 2006, to the Second Lien Credit Agreement among Carrizo Oil & Gas, Inc., CCBM, Inc., CLLR, Inc., the Lenders named therein and Credit Suisse, as collateral agent and administrative agent (incorporated herein by reference to Exhibit 10.1 to the Company s Current Report on Form 8-K filed on December 22, 2006).
10.57	First Amendment to Credit Agreement, Consent and Waiver, effective as of December 19, 2006, among Carrizo Oil & Gas, Inc., the Guarantors party thereto, 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 December 22, 2006).
10.58	Director Compensation.
10.59	Base Salaries and 2006 Annual Bonuses 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.
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, 2006.
99.2	Summary of Reserve Report of Fairchild & Wells, Inc. as of December 31, 2006.
99.3	Summary of Reserve Report of LaRoche Petroleum Consultants, Ltd. as of December 31, 2006.

Incorporated by reference as indicated.

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CARRIZO OIL & GAS, INC.
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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, 2006 and 2005 and the related consolidated statements of operations, shareholders equity and cash flows for each of the three years in the period ended December 31, 2006. 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, 2006 and 2005 and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2006, in conformity with U.S. generally accepted accounting principles.

As referred to in Note 2, effective January 1, 2006, the Company changed its method of accounting for share based payments.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the effectiveness of Carrizo Oil & Gas, Inc. s internal control over financial reporting as of December 31, 2006, based on criteria established in *Internal Control Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO) and our report dated March 30, 2007 expressed an unqualified opinion on management s assessment of the effectiveness of the Company s internal control over financial reporting and an unqualified opinion on the effectiveness of the Company s internal control over financial reporting.

PANNELL KERR FORSTER OF TEXAS, P.C.

Pannell Kerr Forster of Texas, P.C.
Houston, Texas
March 30, 2007

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CARRIZO OIL & GAS, INC.
CONSOLIDATED BALANCE SHEETS

	December 31, 2006	December 31, 2005
	(In thousands)	
ASSETS		
CURRENT ASSETS:		
Cash and cash equivalents	$ 5,408	$ 28,725
Accounts receivable, trade (net of allowance for doubtful accounts of $1,639 and $253 at December 31, 2006 and 2005, respectively)	25,871	24,863
Advances to operators	2,107	1,590
Fair value of derivative financial instruments	5,737	488
Other current assets	1,934	4,518
Total current assets	41,057	60,184
PROPERTY AND EQUIPMENT, net full-cost method of accounting for oil and natural gas properties (including unevaluated costs of properties of $95,136 and $71,581 at December 31, 2006 and 2005, respectively)	445,447	314,074
DEFERRED FINANCING COSTS	4,817	5,858
INVESTMENT IN PINNACLE GAS RESOURCES, INC.	2,771	2,687
OTHER ASSETS	703	298
	$ 494,795	$ 383,101
LIABILITIES AND SHAREHOLDERS EQUITY		
CURRENT LIABILITIES:		
Accounts payable, trade	$ 32,570	$ 17,571
Accrued liabilities	20,885	23,321
Advances for joint operations	1,100	5,887
Current maturities of long-term debt	1,508	1,535
Fair value of derivative financial instruments		1,563
Deferred income tax	2,008	
Total current liabilities	58,071	49,877
LONG-TERM DEBT, net of current maturities	187,250	147,759
ASSET RETIREMENT OBLIGATION	3,625	3,235
FAIR VALUE OF DERIVATIVE FINANCIAL INSTRUMENTS		2,295
DEFERRED INCOME TAXES	32,738	24,550
DEFERRED CREDITS	837	
COMMITMENTS AND CONTINGENCIES		

SHAREHOLDERS EQUITY:		
Common stock, par value $0.01 (40,000,000 shares authorized with 25,980,605 and 24,251,430 issued and outstanding at December 31, 2006 and 2005, respectively)	260	243
Additional paid in capital	168,469	124,586
Retained earnings	49,875	31,627
Unearned compensation restricted stock	(6,330)	(1,071)
Total shareholders equity	212,274	155,385
	$ 494,795	$ 383,101

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

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CARRIZO OIL & GAS, INC.
CONSOLIDATED STATEMENTS OF OPERATIONS

	For the Years Ended December 31,		
	2006	2005	2004
	(In thousands except for per share amounts)		
OIL AND NATURAL GAS REVENUES	$ 82,945	$ 78,155	$ 52,397
COSTS AND EXPENSES:			
Oil and natural gas operating expenses (exclusive of depletion, depreciation and amortization, shown separately below)	16,428	10,437	8,392
Depreciation, depletion and amortization	31,129	21,374	15,464
General and administrative	14,909	11,243	8,255
Accretion expenses related to asset retirement obligation	496	70	23
Total costs and expenses	62,962	43,124	32,134
OPERATING INCOME	19,983	35,031	20,263
OTHER INCOME AND EXPENSES:			
Net gain (loss) on derivatives	16,457	(5,882)	(625)
Loss on extinguishment of debt	(294)	(3,721)	
Equity in income (loss) of Pinnacle Gas Resources, Inc.	35	(2,542)	(1,399)
Other income and expenses, net	427	(457)	506
Interest income	969	904	75
Interest expense	(19,071)	(11,044)	(2,553)
Interest expense, related parties			(1,082)
Capitalized interest	9,975	5,845	2,938
INCOME BEFORE INCOME TAXES	28,481	18,134	18,123
INCOME TAX EXPENSE (Note 5)	10,233	7,500	7,009
NET INCOME	18,248	10,634	11,114
DIVIDENDS AND ACCRETION ON PREFERRED STOCK			350
NET INCOME AVAILABLE TO COMMON SHAREHOLDERS	$ 18,248	$ 10,634	$ 10,764
BASIC EARNINGS PER COMMON SHARE	$ 0.74	$ 0.45	$ 0.54
DILUTED EARNINGS PER COMMON SHARE	$ 0.71	$ 0.44	$ 0.49

WEIGHTED AVERAGE SHARES OUTSTANDING:			
BASIC	24,826,673	23,491,976	19,958,452
DILUTED	25,564,502	24,361,453	21,818,065

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

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

	Warrants		Common Stock	
	Number	Amount	Shares	Amount
	(Dollars in thousands)			
BALANCE, January 1, 2004	3,262,821	$ 780	14,591,348	$ 146
Net income				
Net change in fair value of derivative financial instruments				
Comprehensive income				
Warrants converted	(2,836,605)	(677)	2,067,621	20
Warrants exercised for cash	(92,006)	(23)	92,006	1
Common stock issued, secondary offering, net of offering costs			3,655,500	37
Stock options exercised for cash			436,858	4
Preferred stock conversion			1,318,124	13
Tax benefit of stock options exercised				
Stock option compensation				
Dividends and accretion of discount on preferred stock				
BALANCE, December 31, 2004	334,210	80	22,161,457	221
Net income				
Warrants converted	(250,000)	(75)	250,000	3
Warrants exercised for cash	(84,210)	(5)	54,669	1
Common stock issued, net of offering cost			1,200,000	12
Common stock issued for property			127,068	1
Stock options exercised for cash			370,651	4
Tax benefit of stock options exercised				
Stock option compensation				
Restricted stock awards, net of forfeitures			87,585	1
Amortization of unearned compensation restricted stock				
BALANCE, December 31, 2005		$	24,251,430	243
Net income				
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 at adoption of SFAS 123(R)				
Restricted stock awards, net of forfeitures			277,436	3
			(2,061)	

Common stock repurchased for tax withholding obligations			
Amortization of unearned compensation restricted stock			
BALANCE, December 31, 2006	25,980,605	$	260

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

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

	Additional Paid in Capital	Retained Earnings	Accumulated Other Comprehensive Income (loss)	Unearned Compensation	Shareholders Equity
	(Dollars in thousands)				
BALANCE, January 1, 2004	$ 65,103	$ 10,229	$ (186)	$	$ 76,072
Net income		11,114			11,114
Net change in fair value of derivative financial instruments			186		186
Comprehensive income			$		11,300
Warrants converted	657				
Warrants exercised for cash	224				202
Common stock issued, secondary offering, net of offering costs	23,262				23,299
Stock options exercised for cash	1,650				1,654
Preferred stock conversion	7,452				7,465
Tax benefit of stock options exercised	1,045				1,045
Stock option compensation	373				373
Dividends and accretion of discount on preferred stock		(350)			(350)
BALANCE, December 31, 2004	99,766	20,993			121,060
Net income		10,634			10,634
Warrants converted	997				925
Warrants exercised for cash	79				75
Common stock issued, net of offering cost	17,001				17,013
Common stock issued for property	1,953				1,954
Stock options exercised for cash	1,375				1,379
Tax benefit of stock options exercised	1,486				1,486
Stock option compensation	530				530
Restricted stock awards, net of forfeitures	1,399			(1,412)	(12)
Amortization of unearned compensation restricted stock				341	341
BALANCE, December 31, 2005	124,586	31,627		(1,071)	155,385
Net income		18,248			18,248
	33,403				33,416

Common stock issued, net of offering cost				
Common stock issued for property	55			55
Stock options exercised for cash	601			602
Stock-based compensation	480			480
Capitalization of repriced stock options at adoption of SFAS 123(R)	1,696			1,696
Restricted stock awards, net of forfeitures	7,706		(7,786)	(77)
Common stock repurchased for tax withholding obligations	(58)			(58)
Amortization of unearned compensation restricted stock			2,527	2,527
BALANCE, December 31, 2006	$ 168,469	$ 49,875	$ (6,330)	$ 212,274

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

	For the Year Ended December 31,		
	2006	2005	2004
	(In thousands)		
CASH FLOWS FROM OPERATING ACTIVITIES:			
Net Income	$ 18,248	$ 10,634	$ 11,114
Adjustments to reconcile net income to net cash provided by operating activities -			
Depreciation, depletion and amortization	31,129	21,374	15,464
Fair value loss (gain) of derivative financial instruments	(9,257)	3,610	(400)
Provision for allowance for doubtful accounts	1,386	(72)	325
Accretion of discounts on asset retirement obligations and debt	496	358	177
Loss on extinguishment of debt	294	3,365	
Stock based compensation	2,930	2,453	1,064
Equity in loss of Pinnacle Gas Resources, Inc.	(35)	2,542	1,399
Deferred income taxes	9,829	7,236	6,818
Other	1,237	869	296
Changes in assets and liabilities - Accounts receivable	(990)	(12,087)	(4,094)
Other assets	2,037	(954)	(1,470)
Accounts payable	5,560	(1,890)	(689)
Accrued liabilities	2,573	1,401	2,497
Net cash provided by operating activities	65,437	38,839	32,501
CASH FLOWS FROM INVESTING ACTIVITIES:			
Capital expenditures	(201,773)	(135,156)	(83,891)
Change in capital expenditure accrual	7,791	12,274	4,955
Proceeds from the sale of oil and natural gas properties	38,319	9,037	
Advances to operators	(517)	(1,435)	263
Advances for joint operations	(4,786)	4,078	(1,621)
Other	(610)	(215)	
Net cash used in investing activities	(161,576)	(111,417)	(80,294)
CASH FLOWS FROM FINANCING ACTIVITIES:			
Net proceeds from common stock issuances:			
Private placements, net of offering costs	33,525	17,013	23,299
Warrants exercised		1,000	
Stock option exercises	602	1,379	1,856
Net proceeds from debt issuance and borrowings	80,000	183,624	40,200
Debt repayments	(40,536)	(101,021)	(13,737)
Deferred loan costs and other	(769)	(6,360)	(1,479)
Net cash provided by financing activities	72,822	95,635	50,139
	(23,317)	23,057	2,346

NET INCREASE (DECREASE) IN CASH AND CASH EQUIVALENTS						
CASH AND CASH EQUIVALENTS, beginning of year		28,725		5,668		3,322
CASH AND CASH EQUIVALENTS, end of year	$	5,408	$	28,725	$	5,668
SUPPLEMENTAL CASH FLOW DISCLOSURES:						
Cash paid for interest (net of amounts capitalized)	$	7,211	$	4,253	$	697
Cash paid for income taxes	$		$		$	

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

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CARRIZO OIL & GAS, INC.
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

1. NATURE OF OPERATIONS

Carrizo Oil & Gas, Inc., a Texas corporation; together with its subsidiaries, affiliates and predecessors, (the Company) is an independent energy company formed in 1993 and is engaged in the exploration, development, exploitation and production of oil and natural gas. Its operations are focused along the onshore Gulf Coast of Texas and Louisiana, primarily the Frio, Wilcox and Vicksburg trends and in the Barnett Shale trend in North Texas. The Company, through CCBM, Inc. (a wholly-owned subsidiary) (CCBM), acquired interests in certain oil and natural gas leases in Wyoming and Montana in areas prospective for coalbed methane. During 2003, the Company obtained offshore licensees to explore in the U.K. North Sea and acquired interests in the Barnett Shale trend located in Tarrant and Parker counties in North Texas. During 2005 the Company acquired acreage in shale plays in West Texas/New Mexico, Mississippi/Alabama, Kentucky and Arkansas.

2. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

Principles of Consolidation

The consolidated financial statement 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.

Investment in Unconsolidated Subsidiary

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.

The Company records any loss in fair value of the investment other than a temporary decline.

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, 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 for employees working directly on exploration activities of $3.5 million, $2.1 million and $1.7 million in 2006, 2005 and 2004, respectively. Maintenance and repairs are expensed as incurred.

Depreciation, depletion and amortization (DD&A) and 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 2006, 2005, and 2004 was $2.61, $2.22 and $1.86, 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 through DD&A.

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, DeGolyer and MacNaughton (2005 and 2004), Fairchild & Wells, Inc. and LaRoche Petroleum Consultants (2006), 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.

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 sales volumes are not significantly different from the Company s share of production.

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Financing Costs

Net long-term debt financing costs of $4.8 million and $5.9 million were capitalized and included in other assets as of December 31, 2006 and 2005, respectively, and are being amortized using the effective yield method over the term of the loans through July 2010 for the Second Lien Credit Facility and through May 2010 for the Senior Secured Revolving Credit Facility.

Supplemental Cash Flow Information

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. The Statement of Cash Flows for the year ended December 31, 2005 does not include interest paid-in-kind of $1.3 million, the net exercise of 80,000 warrants for common stock and the acquisition of $2.0 million of oil and gas properties in exchange for the Company s common stock. The Statement of Cash Flows for the year ended December 31, 2004 does not include the net exercise of $0.7 million of warrants and the conversion of $7.5 million of preferred stock into common stock and the $0.3 million relinquishment of interests in certain leases to RMG in lieu of principal payments on a note payable.

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 approximate fair value as these borrowings bear interest at variable interest rates.

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:

	2006	2005	2004
		(In millions)	
Stock Option	$ 0.5	$ 2.1	$ 1.1
Restricted Stock	2.4	0.4	
Total Stock-Based Compensation	$ 2.9	$ 2.5	$ 1.1

Stock Options Prior to January 1, 2006, the Company accounted for stock-based compensation utilizing the intrinsic value method as permitted under Accounting Principles Board (APB) Opinion No. 25, Accounting for Stock Issued to Employees. APB Opinion No. 25 recognized compensation expense only when the market price on the grant date exceeded the option exercise price. In February 2000, the Company repriced certain employee and director stock options and accounted for these repriced stock options in accordance with Financial Accounting Standards Board (FASB) Interpretation No. 44 Accounting for Certain Transactions involving Stock-Based Compensation An Interpretation of APB No. 25 (FIN 44) which prescribes the variable plan accounting treatment for repriced stock options. Under variable plan accounting, compensation expense is adjusted for increases or decreases in the fair market value of the Company s common stock to the extent that the market value exceeds the exercise price of the option until the options are exercised, forfeited, or expire unexercised. Under these accounting guidelines, the Company recognized $2.1 million and $1.1 million of stock-based compensation expense for the years ended December 31, 2005 and 2004, respectively.

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 did not restate prior periods to reflect the impact of adopting the new standard. As part of the adoption of SFAS No. 123(R), the Company stopped recording stock-based compensation expense associated with the February 2000 repriced options mentioned above and the liability associated with the repriced options totaling $2.6 million ($1.7 million, net of tax) was reclassified to shareholders equity during the first quarter of 2006.

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:

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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.

For the year ended December 31, 2006, the Company recognized $0.5 million in stock option compensation expense and has $0.4 million associated with nonvested awards that will be expensed in the future over a weighted-average period of 1.1 years.

The table below summarizes stock option activity for the three years ended December 31, 2006:

	Shares	Weighted-Average Exercise Prices	Weighted-Average Remaining Life (In years)	Aggregate Intrinsic Value (In millions)
For the Year Ended December 31, 2004				
Outstanding, beginning of period	1,637,822	$ 3.63		
Granted	131,668	8.01		
Exercised	(436,858)	3.78		
Forfeited	(7,331)	5.89		
Outstanding, end of period	1,325,301	4.09		
Exercisable, end of period	1,009,243	3.49		
For the Year Ended December 31, 2005				
Outstanding, beginning of period	1,325,301	4.09		
Granted	128,834	15.58		
Exercised	(381,098)	3.82		
Forfeited	(47,833)	5.10		
Outstanding, end of period	1,025,204	5.53		
Exercisable, end of period	754,347	3.67		
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	5.1	$	23.9
Exercisable, end of period	834,799	$	4.65	4.9	$	20.5

The total intrinsic value (current market price less the option strike price) of options exercised during the year ended December 31, 2006 was $2.5 million and the Company received $0.6 million in cash in connection with these exercises.

The following table sets forth pro forma information for years ended December 31, 2005 and 2004 as if stock-based compensation cost had been consistent with the requirements of the SFAS No. 123, Accounting for Stock-based Compensation :

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	For the Year Ended December 31, 2005	For the Year Ended December 31, 2004
	(In thousands except per share amounts)	
Net income available to common shareholders, as reported	$ 10,634	$ 10,764
Add: Stock-based employee compensation expense recognized, net of tax	1,595	691
Less: Total stock-based employee compensation expense determined under fair value method for all awards, net tax	(555)	(578)
Pro forma net income available to common shareholders	$ 11,674	$ 10,877
Net income per common share, as reported:		
Basic	$ 0.45	$ 0.54
Diluted	0.44	0.49
Pro forma net income per common share, as if the fair value method had been applied to all awards:		
Basic	$ 0.50	$ 0.54
Diluted	0.48	0.50

During 2005 and 2004 the Company granted options with a weighted average grant-date fair value of $5.88 and $3.58 per option, respectively, based on the following assumptions:

	2005	2004
Risk-free interest rate	4.3%	4.3%
Dividend yield		
Volatility	46%	43%
Term (in years)	10	10

Restricted Stock. The Company grants shares of restricted stock and records deferred compensation based on the closing 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). The unamortized deferred compensation obligation amounted to $6.3 million as of December 31, 2006. The Company recorded compensation expense related to restricted stock of approximately $2.4 million and $0.4 million for the years ended December 31, 2006 and 2005, respectively. The table below summarizes restricted stock activity for the years ended December 31, 2006 and 2005:

	Shares	Weighted-Average Price
Unvested restricted stock at December 31, 2004		$
Granted	95,325	15.81
Vested		
Forfeited	(7,740)	13.93
Unvested restricted stock 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 at December 31, 2006	326,209	$	25.87

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 windfall. In the case of shortfalls, the difference is charged to equity to the extent of previously recognized windfall tax benefits and any remaining 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, 2006, the Company had an NOL. The Company has postponed the recognition of approximately $0.9

million in windfall tax benefits associated with its stock-based compensation.

Derivative Instruments

The Company uses derivatives to manage price risk underlying its oil and gas production. The Company also uses derivatives to manage the variable interest rate on its Second Lien Credit Facility.

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, 2006, 2005 and 2004 were treated as non-designated derivatives and the unrealized gain/(loss) related to the mark-to-market valuation was included in the Company s earnings.

The Company typically uses fixed-rate swaps and costless collars 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. 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.

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. The Company transacts the majority of its derivative contracts with two counterparties. The Company maintains its cash with major U.S. banks. From time to time, cash amounts may exceed the FDIC insured limit of $100,000. 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.

Major Customers

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

	For the Year Ended December 31,		
	2006	2005	2004
WMJ Investments Corp.			12%
Cokinos Natural Gas Company			17%
Reichmann Petroleum	10%	11%	
Texon L.P.			13%
Chevron/Texaco	11%	12%	

Earnings Per Share

Supplemental earnings per share information is provided below:

	For the Year Ended December 31,		
	2006	2005	2004
	(In thousands except share and per share amounts)		
Net income available to common shareholders	$ 18,248	$ 10,634	$ 10,764
Basic weighted average common shares outstanding	24,826,673	23,491,976	19,958,452
Restricted stock, stock options and warrants	737,829	869,477	1,859,613
Diluted weighted average shares outstanding	25,564,502	24,361,453	21,818,065
Earnings per share			
Basic	$ 0.74	$ 0.45	$ 0.54
Diluted	$ 0.71	$ 0.44	$ 0.49

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 2,500, 2,500 and 30,000 stock options at December 31, 2006, 2005 and 2004, respectively, that were antidilutive.

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 FASB issued SFAS No. 143, Accounting for Asset Retirement Obligations. 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.

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

	2006	2005
	(In thousands)	
Asset retirement obligation at beginning of year	$ 3,235	$ 1,407
Liabilities incurred	1,194	593
Liabilities settled	(406)	(62)
Accretion expense	496	70
Revisions to previous estimates	(894)	1,227
Asset retirement obligation at end of year	$ 3,625	$ 3,235

Recently Issued Accounting Pronouncements

In July 2006, the FASB issued FASB Interpretation No. 48, Accounting for Uncertainty in Income Taxes an Interpretation of FASB Statement 109 (FIN 48), which clarifies the accounting for uncertainty in tax positions taken or expected to be taken in a tax return, including issues relating to financial statement recognition and measurement. FIN 48 provides that the tax effects from an uncertain tax position can be recognized in the financial statements only if the position is more-likely-than-not of being sustained if the position were to be challenged by a taxing authority. The assessment of the tax position is based solely on the technical merits of the position, without regard to the likelihood that the tax position may be challenged. If an uncertain tax position meets the more-likely-than-not threshold, the largest amount of tax benefit that is greater than 50 percent likely of being recognized upon ultimate settlement with the taxing authority, is recorded. The provisions of FIN 48 are effective for fiscal years beginning after December 15, 2006, with the cumulative effect of the change in accounting principle recorded as an adjustment to opening retained earnings. We are currently evaluating the impact of adopting FIN 48 on our consolidated financial statements.

In September 2006, the FASB issued SFAS No. 157, Fair Value Measurements. SFAS No. 157 defines fair value, establishes a framework for measuring fair value under Generally Accepted Accounting Principles and requires enhanced disclosures about fair value measurements. It does not require any new fair value measurements. SFAS No. 157 is effective for financial statements issued for fiscal years beginning after November 15, 2007 and interim periods within those fiscal years. We are currently assessing whether we will early adopt SFAS No. 157 as of the first quarter of fiscal 2007 as permitted, and are currently evaluating the impact adoption may have on our consolidated financial statements.

In September 2006, the FASB issued SFAS No. 158 Employers Accounting for Defined Benefit Pension and Other Postretirement Plans. This Statement amends Statement 87, FASB Statement No. 88, Employers Accounting for Settlements and Curtailments of Defined Benefit Pension Plans and for Termination Benefits, Statement 106, and FASB Statement No. 132 (revised 2003), Employers Disclosures about Pensions and Other Postretirement Benefits, and other related accounting literature. SFAS No. 158 requires an employer to recognize the overfunded or underfunded status of a defined benefit postretirement plan (other than a multiemployer plan) as an asset or liability in its statement of financial position and to recognize changes in the funded status in the year in which the changes occur through comprehensive income. This statement also requires employers to measure the funded status of a plan as of the date of its year-end statement of financial position, with limited exceptions. Employers with publicly traded equity securities are required to initially recognize the funded status of a defined benefit postretirement plan and to provide the required disclosures as of the end of the fiscal year ending after December 15, 2006. We currently have no defined benefit or other post retirement plans subject to this standard.

In February 2007, the FASB issued SFAS No. 159, The Fair Value Option for Financial Assets and Financial Liabilities, which permits entities to choose to measure many financial instruments and certain other items at fair value. The objective is to improve financial reporting by providing entities with the opportunity to mitigate volatility in reported earnings caused by measuring related assets and liabilities differently without having to apply complex hedge accounting provisions. SFAS No. 159 applies to all entities and is effective for fiscal years beginning after November 15, 2007. The Company is currently determining the impact, if any, that SFAS No. 159 will have on its financial statements.

Recently Adopted Accounting Pronouncements

On December 16, 2004, the FASB issued SFAS No. 123 (revised 2004), Share-Based Payment (SFAS No. 123(R)). SFAS No. 123(R) requires companies to measure all employee stock-based compensation awards using a fair value method and record such expense in their consolidated financial statements. In addition, the adoption of SFAS No. 123(R) requires additional accounting and disclosure related to the income tax and cash flow effects resulting from share-based payment arrangements. SFAS No. 123(R) was effective beginning as of the first annual reporting period after June 15, 2005. We adopted the provisions of SFAS No. 123(R) during the first quarter of 2006 using the modified prospective method for transition and recognized approximately $0.5 million in stock-based compensation expense for the year ended December 31, 2006.

3. INVESTMENT IN PINNACLE GAS RESOURCES, INC.

The Pinnacle Transaction

On June 23, 2003, pursuant to a Subscription and Contribution Agreement by and among the Company and its wholly-owned subsidiary, CCBM, Inc., Rocky Mountain Gas, Inc. (RMG) and the Credit Suisse First Boston Private Equity entities, named therein (the CSFB Parties), CCBM and RMG contributed their respective interests, having a estimated fair value of approximately $7.5 million each, in (1) leases in the Clearmont, Kirby, Arvada and Bobcat project areas and (2) oil and natural gas reserves in the Bobcat project area to a newly formed entity, Pinnacle Gas Resources, Inc., a Delaware corporation. In exchange for the contribution of these assets, CCBM and RMG each received 37.5% of the common stock of Pinnacle (Pinnacle Common Stock) as of the closing date and options to purchase Pinnacle Common Stock (Pinnacle Stock Options). RMG subsequently transferred its interest in Pinnacle to U.S. Energy Corp. CCBM no longer has a drilling obligation in connection with the oil and natural gas leases contributed to Pinnacle.

Simultaneously with the contribution of these assets, the CSFB Parties contributed approximately $17.6 million of cash to Pinnacle in return for the Redeemable Preferred Stock of Pinnacle (Pinnacle Preferred Stock), 25% of the Pinnacle Common Stock as of the closing date and warrants to purchase Pinnacle Common Stock (Pinnacle Warrants). The CSFB Parties also agreed to contribute additional cash, under certain circumstances, of up to approximately $11.8 million to Pinnacle to fund future drilling, development and acquisitions.

Immediately following the contribution and funding, Pinnacle used approximately $6.2 million of the proceeds from the funding to acquire an approximate 50% working interest in existing leases and acreage prospective for coalbed methane development in the Powder River Basin of Wyoming from Gastar Exploration, Ltd. Pinnacle also agreed to fund up to $14.9 million of future drilling and development costs on these properties on behalf of Gastar prior to December 31, 2005. The drilling and development work was done under the terms of an earn-in joint venture agreement between Pinnacle and Gastar. The majority of these leases are part of, or adjacent to, the Bobcat project area. All of CCBM and RMG s interests in the Bobcat project area, the only producing coalbed methane property owned by CCBM prior to the transaction, were contributed to Pinnacle.

CCBM continues its coalbed methane business activities and, in addition to its interest in Pinnacle, owns direct interests in acreage in coalbed methane properties in the Castle Rock project area in Montana and the Oyster Ridge project area in Wyoming, which were not contributed to Pinnacle. CCBM will continue to conduct exploration and development activities on these properties as well as pursue other potential acquisitions. Other than indirectly through Pinnacle, CCBM currently has no proved reserves of, and is no longer receiving revenue from, coalbed methane gas.

In March 2004, the CSFB Parties contributed additional funds of $11.8 million into Pinnacle to continue funding the 2004 development program. In 2005, the CSFB Parties contributed $15.0 million to Pinnacle to finance an acquisition of additional undeveloped acreage. CCBM and U.S. Energy elected not to participate in either of these equity contributions. In November 2005, the CSFB Parties and a former Pinnacle employee received 30,000 and 2,000 shares of Pinnacle common stock, respectively, after exercising certain warrants and options.

In April 2006, prior to and in connection with a private placement by Pinnacle of 7,400,000 shares of its common stock, Pinnacle issued 25 new shares of its common stock to each of its stockholders in exchange for each existing share in a stock split; Pinnacle redeemed the preferred stock held by the CSFB Parties at 110% of par value; the CSFB Parties exercised all of their warrants on a cashless net exercise basis; and CCBM and U.S. Energy exercised their respective options on a cashless net exercise basis. On April 11, 2006, after the stock split, the redemption of the preferred stock, the warrant and option exercises and the private placement, CCBM owned 2,459,102 shares of Pinnacle s common stock, and its ownership of Pinnacle was 9.5% on a fully diluted basis. On such date, U.S. Energy and the CSFB Parties owned 2,459,102 and 7,306,782 shares of Pinnacle s common stock, respectively, and their ownership of Pinnacle was 9.5% and 28.3% on a fully diluted basis, respectively. On September 22, 2006, U.S. Energy sold all of its 2,459,102 shares of Pinnacle s common stock to the CSFB Parties. At December 31, 2006, CCBM owned 2,459,102 shares of Pinnacle s common stock, and its ownership of Pinnacle was 9.5% on a fully diluted basis.

Prior to the April 2006 Pinnacle private placement, the Company accounted for its interest in Pinnacle using the equity method. Beginning in the second quarter of 2006, the Company used the cost method to account for the

Pinnacle investment.

For accounting purposes, the Pinnacle contribution in 2003 was treated as a reclassification of a portion of CCBM s investments in the contributed properties. The property contribution made by CCBM to Pinnacle is intended to be treated as a tax-deferred exchange as constituted by property transfers under section 351(a) of the Internal Revenue Code of 1986, as amended.

The reclassification of investments in contributed properties resulting from the transaction with Pinnacle are reflected in accordance with the full cost method of accounting in the Company s balance sheets at December 31, 2006 and 2005.

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4. PROPERTY AND EQUIPMENT

At December 31, 2006 and 2005, property and equipment consisted of the following:

	December 31, 2006	December 31, 2005
	(In thousands)	
Proved oil and natural gas properties	$ 482,715	$ 345,081
Unproved oil and natural gas properties	95,136	71,581
Other equipment	2,106	891
Total property and equipment	579,957	417,553
Accumulated depreciation, depletion and amortization	(134,510)	(103,479)
Property and equipment, net	$ 445,447	$ 314,074

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 unproved 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.

5. INCOME TAXES

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

	For the Year Ended December 31, 2006	2005	2004
		(In thousands)	
Provision at the statutory tax rate	$ 9,968	$ 6,347	$ 6,343
Preferred dividend on Pinnacle	141	626	405
Increase (decrease) in valuation allowance for equity in (income) loss of Pinnacle	(153)	264	70
State taxes	277	263	191
Income tax expense	$ 10,233	$ 7,500	$ 7,009

Deferred income tax provisions result from temporary differences in the recognition of income and expenses for financial reporting purposes and for tax purposes. At December 31, 2006 and 2005, the tax effects of these temporary differences resulted principally from the following:

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	December 31, 2006	December 31, 2005
	(In thousands)	
Deferred income tax assets:		
Net operating loss carryforward	$ 13,361	$ 7,551
Stock based compensation	868	913
Fair value derivative instruments		1,350
Equity in income (loss) of Pinnacle	385	538
Valuation allowance	(385)	(538)
	14,229	9,814
Deferred income tax liabilities:		
Oil and gas acquisition, exploration and development costs deducted for tax purposes in excess of financial statement DD&A	35,733	25,848
Capitalized interest	11,234	7,742
Fair value derivative instruments	2,008	227
	48,975	33,817
Net deferred income tax liability	$ 34,746	$ 24,003

At December 31, 2006 and 2005, the net deferred income tax liability is classified as follows:

	December 31, 2006	December 31, 2005
	(In thousands)	
Other current assets	$	$ (547)
Current deferred income tax liability	2,008	
Deferred income tax liability	32,738	24,550
Deferred income tax liability, net	$ 34,746	$ 24,003

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. It is more unlikely than not that Pinnacle will not realize the tax benefit. The Company has a net operating loss carryforward totaling approximately $38.2 million, which begins expiring in 2009 through 2026.

6. LONG-TERM DEBT

At December 31, 2006 and 2005, long-term debt consisted of the following:

	December 31, 2006	December 31, 2005

	(In thousands)	
Second Lien Credit Facility	$ 147,750	$ 149,250
Senior Secured Revolving Credit Facility	41,000	
Capital lease obligations		27
Other	8	17
	188,758	149,294
Less: current maturities	(1,508)	(1,535)
	$ 187,250	$ 147,759

First Lien Credit Facility

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On September 30, 2004, the Company entered into a Second Amended and Restated Credit Agreement with Hibernia National Bank and Union Bank of California, N.A. (the First Lien Credit Facility), which was to mature on September 30, 2007. The First Lien Credit Facility provided for (1) a revolving line of credit of up to the lesser of the Facility A Borrowing Base and $75.0 million and (2) a term loan facility of up to the lesser of the Facility B Borrowing Base and $25.0 million (subject to the limit of the borrowing base, which was $22.5 million as of March 31, 2006). It was secured by substantially all of the Company s assets and was guaranteed by the Company s subsidiary, CCBM, Inc. On May 25, 2006, the Company terminated the First Lien Credit Facility upon entering into the Senior Credit Facility (discussed below).

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 (the Agent) and the lenders party thereto (the Second Lien Credit Facility) that matures on July 21, 2010. The Second Lien Credit Facility provides for a term loan facility in an aggregate principal amount of $150.0 million. It is secured by substantially all of the Company s assets and is guaranteed by the Company s subsidiaries. The liens securing the Second Lien Credit Facility were second in priority to the liens securing the First Lien Credit Facility prior to its termination in May 2006, as discussed above, and are second in priority to the liens securing the Senior Credit Facility (discussed below).

On December 20, 2006, the Company, entered into an amendment, effective as of December 19, 2006, to the Second Lien Credit Facility (the December 2006 Amendment). The amendment increased the principal amount available for borrowings under the Second Lien Credit Facility from $150 million to $225 million. The amendment also included the following, without limitation: (1) a reduction in the interest rate on each Eurodollar loan such that it is the adjusted LIBO rate plus a margin of 4.75%; (2) a reduction in the interest rate on each base rate loan such that it is (i) the greater of the Agent s prime rate and the federal funds effective rate plus 0.5%, plus (ii) a margin of 3.75%; (3) an adjustment to the minimum quarterly interest coverage ratio such that it is 2.75 to 1.0 through and including December 31, 2007 and 3.0 to 1.0 thereafter; (4) an adjustment to the minimum quarterly proved reserve coverage ratio such that it is 1.5 to 1.0 through December 31, 2007 and 2.0 to 1.0 thereafter; and (5) a maximum total net recourse debt to EBITDA ratio of not more than 3.75 to 1.0 through December 31, 2007 and 3.25 to 1.0 thereafter.

The interest rate on each base rate loan will be the greater of the Agent s prime rate and the federal funds effective rate plus 0.5%, plus a margin of 3.75%. The interest on each Eurodollar loan will be the adjusted LIBO rate plus a margin of 4.75%. Interest on Eurodollar loans is payable on either the last day of each period or every three months whichever is earlier. Interest on the Company s outstanding borrowings under the Second Lien Credit Facility is payable quarterly. On December 31, 2006, the interest rate was approximately 10.11%, excluding the impact of interest rate swaps.

The Company is subject to certain covenants under the amended terms of the Second Lien Credit Facility. These covenants include, but are not limited to, the maintenance of the following financial covenants: (1) a minimum current ratio of 1.0 to 1.0 including availability under the borrowing base under the Senior Credit Facility; (2) a minimum quarterly interest coverage ratio of 2.75 to 1.0 through December 31, 2007 and 3.0 to 1.0 thereafter; (3) a minimum quarterly proved reserve coverage ratio of 1.5 to 1.0 through December 31, 2007 and 2.0 to 1.0 thereafter; and (4) a maximum total net recourse debt to EBITDA (as defined in the Second Lien Credit Facility) ratio of not more than 3.75 to 1.0 through December 31, 2007 and 3.25 to 1.0 thereafter.

The Second Lien Credit Facility also places restrictions on additional indebtedness, dividends to shareholders, liens, investments, mergers, acquisitions, asset dispositions, repurchase or redemption of the Company s common stock, speculative commodity transactions, transactions with affiliates and other matters.

The Second Lien Credit Facility is subject to customary events of default. Subject to certain exceptions, if an event of default occurs and is continuing, the Agent may accelerate amounts due under the Second Lien Credit Facility (except for a bankruptcy event of default, in which case such amounts will automatically become due and payable). If an event of default occurs under the Second Lien Credit Facility as a result of an event of default under the Senior Credit Facility, the Agent may not accelerate the amounts due under the Second Lien Credit Facility until the earlier of 45 days after the occurrence of the event resulting in the default and acceleration of the loans under the Senior Credit Facility.

As of December 31, 2006, the Company had $147.8 million of borrowings outstanding under the Second Lien Credit Facility. Maturities of long-term debt are $1.5 million in each of the years 2007 through 2009 and the balance of $184.3 million is due in 2010. In January 2007, the Company drew the additional $75.0 million in borrowings and received net proceeds of $72.1 million related to the December 2006 Amendment.

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 that matures on May 25, 2010. The Senior Credit Facility provides 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 assets and is guaranteed by our subsidiaries. The liens securing the Senior Credit Facility are first in priority to the liens securing the Second Lien Credit Facility.

As of December 31, 2006, the Company had $41.0 million of borrowings outstanding on a borrowing base availability of $65.0 million.

On December 20, 2006, the Company amended its Senior Credit Facility (the Senior Credit Amendment) in connection with the aforementioned December 2006 Amendment. On January 3, 2007, the Company drew the $75.0 million of additional borrowings from its Second Lien Credit Facility, using a portion of the net proceeds to repay the $41.0 million of outstanding borrowings under the Senior Credit Facility.

Following the repayment of the outstanding borrowings on January 3, 2007, the amended and undrawn borrowing base was $54.25 million, with a conforming borrowing base of $46.75 million and subject to monthly reductions of $1.69 million commencing May 1, 2007 and continuing on the first day of each month thereafter until the borrowing base is redetermined. We may request one unscheduled borrowing base determination subsequent to each scheduled determination, and the lenders may request unscheduled determinations at any time. In the event the outstanding principal balance of indebtedness under the Second Lien Credit Facility exceeds $225.0 million, the borrowing base under the Senior Credit Facility will be reduced $1.00 for every $4.00 of such additional indebtedness under the Second Lien Credit Facility.

If the outstanding principal balance of the revolving loans under the Senior Credit Facility exceeds the borrowing base at any time, we have the option within 30 days to take any of the following actions, either individually or in combination: make a lump sum payment curing the deficiency, pledge additional collateral sufficient in the lenders opinion to increase the borrowing base and cure the deficiency or begin making equal monthly principal payments that will cure the deficiency within the ensuing six-month period. Those payments would be in addition to any payments that may come due as a result of the quarterly borrowing base reductions. Otherwise, any unpaid principal or interest will be due at maturity.

The annual interest rate on each base rate borrowing will be (1) 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 (2) a margin between 0.25% and 1.75% (depending on the current level of borrowing base usage). The interest rate on each Eurodollar Loan will be the adjusted LIBO rate plus a margin between 1.5% to 3.0% (depending on the current level of borrowing base usage).

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 3.75 to 1.0 for the fiscal quarters through and including December 31, 2007, 3.25 to 1.0 for the fiscal quarter March 31, 2008 and thereafter. The Senior Credit Facility also places restrictions on indebtedness, dividends to shareholders, liens, investments, mergers, acquisitions, asset dispositions, repurchase or redemption of the Company s 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, 2006, the Company was in compliance with all of its debt covenants.

At December 31, 2006, one letter of credit totaling $500,000 was outstanding.

7. CONVERTIBLE PARTICIPATING PREFERRED STOCK

In February 2002, the Company consummated the sale of 60,000 shares of Convertible Participating Series B Preferred Stock (the Series B Preferred Stock) and warrants to purchase 252,632 shares of common stock for an aggregate purchase price of $6.0 million. The Company sold 40,000 and 20,000 shares of Series B Preferred Stock and 168,422 and 84,210 warrants to Mellon Ventures, Inc. and Steven A. Webster, respectively. The Series B Preferred Stock was convertible into common stock by the investors at a conversion price of $5.70 per share, subject to adjustments, and was initially convertible into 1,052,632 shares of common stock. The warrants had a five-year term and entitled the holders to purchase up to 252,632 shares of Carrizo s common stock at a price of $5.94 per share, subject to adjustments, and were exercisable at any time after issuance. The warrants were exercisable on a cashless exercise basis. Dividends on the Series B Preferred Stock were payable in either cash at a rate of 8% per annum or, at the Company s option, by payment in kind of additional shares of the same series of preferred stock at a rate of 10%

per annum. At December 31, 2003 and through the conversion dates specified below, the outstanding balance of the Series B Preferred Stock was increased by $1.2 million (11,987 shares) and $1.5 million (15,133 shares), respectively, for dividends paid in kind. The Series B Preferred Stock was redeemable at varying prices in whole or in part at the holders option after three years or at the Company s option at any time. The Series B Preferred Stock also participated in any dividends declared on the common stock. Mellon Ventures, Inc. converted all of its Series B Preferred Stock (approximately 49,938 shares) into 876,099 shares of common stock on May 25, 2004. Steven A. Webster converted all of his Series B Preferred Stock (approximately 25,195 shares) into 442,026 shares of common stock on June 30, 2004. As a result, no shares of Series B Preferred Stock were outstanding at December 31, 2005. The total value of the Series B Preferred Stock upon conversion was $7.5 million and was reclassified to stockholders equity following the conversion.

During 2004, Mellon Ventures, Inc. exercised all of its 168,422 warrants on a cashless exercise basis for a total of 36,570 shares of common stock and during 2005, Mr. Webster exercised all of his 84,210 warrants on a cashless basis, receiving a total of 54,669 shares of common stock.

Net proceeds of the sale of the Series B Preferred Stock were approximately $5.8 million and were used primarily to fund the Company s ongoing exploration and development program and general corporate purposes.

8. COMMITMENTS AND CONTINGENCIES

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

The 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.

In September 2005, the Company entered into an agreement to purchase over an 18 month period a non-exclusive license to certain geophysical data at a cost of $2.0 million. The license provides the Company the rights to selection of geophysical data located in Texas and Louisiana and all selections must be completed on or before March 31, 2007.

Effective December 2004, the Company relocated its offices and entered into a new long-term operating lease agreement that expires 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. Rent expense for the years ended December 31, 2006, 2005 and 2004 was $0.6 million, $0.5 million and $0.2 million, respectively.

Minimum rentals, drilling obligations and scheduled seismic data purchases for each of the five years subsequent to December 31, 2006 are as follows (in thousands):

	Amount
2007	$ 13,587
2008	980
2009	999
2010	1,102
2011	1,102
Thereafter	
	$ 17,770

In addition to the contractual obligations presented above, the Company is also party to a firm well commitment agreement in the North Sea to drill one well within the next four years. The Company expects to incur between $4.0 million and $6.0 million to drill the well between 2007 and 2010.

9. SHAREHOLDERS EQUITY

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.

In June 2005, the Company sold 1.2 million shares of the Company s common stock to institutional investors (the Investors) at a price of $15.25 per share in a private placement. The number of shares sold was approximately 5% of the fully diluted shares outstanding before the offering. The net proceeds, after deducting placement agents fees but before paying offering expenses, were approximately $17.2 million. The Company used the proceeds from the private placement to fund a portion of its capital expenditure program for 2005, including the drilling programs in the Barnett Shale and onshore Gulf Coast areas.

In the first quarter of 2004, the Company completed the public offering of 6,485,000 shares of common stock at $7.00 per share generating net proceeds of approximately $23.4 million. The offering included 3,655,500 newly issued shares offered by the

Company and 2,829,500 shares offered by certain selling shareholders. The Company did not receive any proceeds from the shares sold by the selling shareholders. The Company used part of the net proceeds from this offering to accelerate its drilling program and to retain larger interests in portions of its drilling prospects that the Company otherwise would sell down or for which the Company would seek joint partners and for general corporate purposes. Initially, the Company used a portion of the net proceeds to repay the $7 million outstanding principal amount under its revolving credit facility and to complete an $8.2 million Barnett Shale acquisition on February 27, 2004.

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 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 covering 2,051,667 shares through December 31, 2006, net of forfeitures. Through that date, 1,000,434 options had been exercised. During 2006, a total of 277,436 restricted stock awards (net of forfeitures) were granted which are subject to pro rata vesting over a one to three-year period. These awards had a grant date fair value totaling $8.4 million that were recorded as deferred compensation and which are being amortized as compensation expense over the respective vesting periods of the awards. The Company incurred $2.9 million, $2.5 million and $1.1 million related to stock-based compensation during the years ended December 31, 2006, 2005 and 2004, respectively.

The Company issued 1,729,175, 2,089,973, and 7,570,109 shares of common stock during the years ended December 31, 2006, 2005 and 2004, respectively. The shares issued during the year ended December 31, 2006 consisted of 1,350,000 shares issued in the 2006 private placement, 2,000 shares issued in connection with the acquisition of certain oil and gas properties, 277,436 shares issued as restricted stock awards granted under the incentive plan and 101,800 shares issued through the exercise of options granted under the Incentive Plan. In addition, during 2006 the Company repurchased 2,061 shares related to tax withholding obligations associated with the vesting of restricted stock. The shares issued during the year ended December 31, 2005 consisted of 1,200,000 shares issued in the 2005 private placement, 127,068 shares issued in connection with the acquisition of certain oil and gas properties, 304,669 shares issued through the exercise of warrants, 87,585 shares issued as restricted stock awards granted under the Incentive Plan and 370,651 shares issued through the exercise of 381,098 options granted under the Incentive Plan. Of these options exercised in 2005, 34,169 were exercised on a cashless basis resulting in 23,722 shares being issued. The shares issued during the year ended December 31, 2004 consisted of 3,655,500 shares issued through the 2004 public offering, 2,159,627 shares issued through the exercise of warrants, 1,318,124 shares issued through the conversion of Series B Preferred Stock and 436,858 shares issued through the exercise of options granted under the Company s Incentive Plan.

10. RELATED-PARTY TRANSACTIONS

Due to the limited capital available in the first half of 2006 to fund all of the Company s ongoing lease acquisition efforts in the Barnett Shale and other shale plays, the Company elected to enter into several lease option agreements with a number of third parties and with Steven A. Webster, the Company s chairman (collectively, the counterparties). The terms and conditions of the leasing arrangement (agreement terms are described below) with Mr. Webster are consistent with the leasing arrangements the Company has entered into with the other third parties. These leasing 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. Strategically, these leasing arrangements have allowed the Company to temporarily control important acreage positions during periods that the Company has lacked sufficient capital to directly acquire such oil and gas leases.

Since May 2006, the Company has acquired certain oil and gas leases through the aforementioned lease option arrangement with Mr. Webster. The acquisitions were made pursuant to a land option agreement between Mr. Webster and the Company dated January 25, 2006. The terms and conditions of this leasing arrangement with Mr. Webster are consistent with leasing arrangements the Company has entered into with the other third parties. Under the option agreement, Mr. Webster agreed to acquire oil and gas leases in areas where the Company is actively leasing or that it deems prospective. On or before the 90th day from the date that Mr. Webster acquires any lease in these areas, the Company has the option to acquire these leases from Mr. Webster for 110% of Mr. Webster s purchase price or, on the 90th day, pay a non-refundable 10% option extension fee to add a second 90-day option period. On or before the end of this second 90-day option period, the Company has the option to pay Mr. Webster 110% of his original purchase price to acquire the lease. If, at the end of the second option period, the Company has not exercised its purchase option, Mr. Webster will retain ownership of the oil and gas leases. In addition to the cash payments described above, the Company will assign a one-half of one percent of 8/8ths overriding royalty interest (proportionally reduced to the actual net interest in any given lease acquired) on any lease it acquires from Mr. Webster in the first 90-day option period and a one percent of 8/8ths overriding royalty interest (also proportionally reduced) on any lease acquired from Mr. Webster in the second 90-day option period. As of December 31, 2006, Mr. Webster has acquired oil and gas leases for approximately $4.2 million, the Company paid approximately $4.4 million for leases from Mr. Webster and the Company has made option extension payments of approximately $48,000 to Mr. Webster. There are currently no outstanding lease options under our arrangement with Mr. Webster. The Company may continue to use these arrangements as a strategic alternative.

The Company s Chairman of the Board, Mr. Steve Webster serves as member on the Board of Directors for Grey Wolf Drilling, Basic Energy Services, Inc., Brigham Exploration, Quantum Geophysical, Inc. and Goodrich Petroleum. The Company s Chief Executive Officer, Mr. S.P. Johnson serves as member on the Board of Directors for Basic Energy Services, Inc. Due to these relationships, the Company has deemed these companies to be related parties. The Company incurred the following costs with these related parties:

	For the Year Ended December 31,		
	2006	2005	2004
		(In millions)	
Grey Wolf Drilling	$ 6.7	$	$1.6
Basic Energy Services	0.5	0.4	0.4
Brigham Exploration	(0.6)[1]	0.2	
Quantum Geophysical Inc.	0.2	1.5	1.2
Goodrich Petroleum			0.6

(1) 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, resulting in a net receivable balance.

It is management s opinion that the transactions with these entities were executed at prevailing market rates. At December 31, 2006 and 2005, the Company had an outstanding related-party net receivable balance of $0.2 million and a payable balance of $0.1 million, respectively.

See Notes 3 and 7 for a discussion of the investment in Pinnacle and Series B Preferred Stock with parties that include members of the Company s Board of Directors or their affiliates.

Steven A. Webster, Chairman of the Board of the Company, is also Chairman of Avista Capital Holdings, L.P. and is therefore a related party to the Pinnacle transaction.

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 Company L.P. (Black Stone Minerals). Thomas L. Carter, Jr., a member of the Company s board of directors, is the Chief Executive Officer and an owner of a significant interest in Black Stone Minerals. Black Stone Acquisition Partners also retains a royalty interest in the acquired leases, which are located in Mississippi. The terms and conditions of the lease agreement with Black Stone Acquisitions Partners I L.P. are generally consistent with the lease agreements that the Company has entered into with other third parties. Additionally, the Company operates three producing wells in which affiliates of Black Stone Minerals hold a royalty interest, acquired from an unrelated third party.

11. 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 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 Expense in the Consolidated Statement of Operations. For the years ended December 31, 2006, 2005 and 2004, the Company recorded the following related to its derivatives:

	For the Year Ended December 31, 2006	2005	2004
		(In millions)	
Realized gain (loss)			
Natural gas and oil derivatives	$ 5.6	$ (2.3)	$ (1.0)
Interest rate swaps	1.0		
Gain on interest rate swap sell down	0.6		
	7.2	(2.3)	(1.0)
Unrealized gain (loss)			
Natural gas and oil derivatives	9.9	(4.2)	0.4
Interest rate swaps	(0.6)	0.6	
	9.3	(3.6)	0.4
Net Gain (Loss) on Derivatives	$ 16.5	$ (5.9)	$ (0.6)

At December 31, 2006 the Company had the following outstanding derivative positions:

	Swaps		Collars		
Quarter	**MMbtu**	**Average Fixed Price[(1)]**	**MMBtu**	**Average Floor Price[(1)]**	**Average Ceiling Price[(1)]**
First Quarter 2007	1,257,000	$ 7.60	630,000	$ 7.95	$ 9.81
Second Quarter 2007	729,000	7.47	728,000	7.31	8.87
Third Quarter 2007	552,000	7.48	552,000	7.53	9.10
Fourth Quarter 2007	552,000	7.48	276,000	6.92	8.32
First Quarter 2008	273,000	7.94	546,000	7.32	8.95
Second Quarter 2008	273,000	7.94	364,000	7.35	9.10
Third Quarter 2008	276,000	7.94	368,000	7.35	9.10
Fourth Quarter 2008	276,000	7.94	368,000	7.35	9.10

(1) Based on Houston Ship Channel spot prices.

The fair value of the outstanding derivatives at December 31, 2006 and 2005 was an asset of $6.0 million and a liability of $3.4 million, respectively.

In November 2001, the Company had no-cost collars with an affiliate of Enron Corp. which, because of Enron s financial condition, were no longer considered effective. An allowance was recorded at that time for the full value of the collars (the Enron Claim) that was classified as other expense. The Company sold its Enron Claim to a financial institution for $0.5 million that was recorded in the third quarter of 2004 as other income.

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 the amendment to the Company s 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. On January 5, 2007, the Company opened new derivative positions in the form of interest rate swaps on the entire outstanding principal of its Second Lien Credit Facility, covering the year ended December 31, 2007.

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:

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	For the Year Ended December 31,		
	2006	2005	2004
	(In thousands)		
Property acquisition costs			
Unproved	$ 48,409	$ 49,089	$ 21,831
Proved		1,954	8,357
Exploration costs	104,473	50,303	39,181
Development costs	37,889	20,883	12,697
Asset retirement obligation	299	1,820	529
Total costs incurred*	$ 191,070	$ 124,049	$ 82,595

(1) Excludes capitalized interest on unproved properties of $10.0 million, $5.8 million and $2.9 million for the years ended December 31, 2006, 2005 and 2004, respectively, and includes capitalized overhead of $3.5 million, $2.1 million and $1.7 million for the years ended December 31, 2006, 2005 and 2004, respectively. The table also includes non-cash asset retirement obligations of $0.3 million, $1.8 million and $0.5 million for the years ended December 31, 2006, 2005 and

2004,
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, 2006, 2005 and 2004, and the related discounted future net cash flows before income taxes are based on estimates prepared by Ryder Scott Company, DeGolyer and MacNaughton (2005 and 2004) and Fairchild & Wells, Inc., and LaRoche Petroleum Consultants (2006) independent petroleum engineers. 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,		
	2006	**2005**	**2004**
Proved developed and undeveloped reserves -			
Beginning of year	103,058	54,621	18,069
Purchase of oil and natural gas properties in place		4,634	13,390
Discoveries and extensions	91,090	57,513	32,002
Revisions	(11,026)	(5,102)	(2,378)
Sales of oil and gas properties in place	(6,148)	(402)	
Production	(10,176)	(8,206)	(6,462)
End of year	166,798	103,058	54,621
Proved developed reserves at beginning of year	44,681	28,066	17,098
Proved developed reserves at end of year	73,912	44,681	28,066

	Thousands of Barrels of Oil and Condensate at December 31,		
	2006	**2005**	**2004**
Proved developed and undeveloped reserves -			
Beginning of year	7,925	9,118	8,714
Purchase of oil and natural gas properties in place		5	5
Discoveries and extensions	359	253	208
Revisions	(823)	(1,211)	500
Sales of oil and gas properties in place	(11)	(6)	
Production	(255)	(234)	(309)
End of year	7,195	7,925	9,118
Proved developed reserves at beginning of year	1,343	1,459	1,395
Proved developed reserves at end of year	1,638	1,343	1,459

Carrizo uses the cost method of accounting to record its investment in Pinnacle, formed in June 2003. Accordingly, the proved reserve tables, above, do not include the Company s interest ownership, 9.5% on a fully diluted basis, in the proved reserves of Pinnacle at the end of 2006, or an estimated 1.9 Bcfe of proved reserves.

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,		
	2006	**2005**	**2004**
		(In thousands)	
Future cash inflows	$ 1,356,118	$ 1,269,551	$ 685,598
Future oil and natural gas operating expenses	350,076	377,304	244,618
Future development costs	193,245	162,594	55,730
Future income tax expenses	202,685	195,920	108,295
Future net cash flows	610,112	533,733	276,955
10% annual discount for estimating timing of cash flows	311,401	234,392	127,234
Standard measure of discounted future net cash flows	$ 298,711	$ 299,341	$ 149,721

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 2006, 2005 and 2004 future cash flows were $54.73, $57.17 and $41.18 for oil, respectively, and $5.77, $8.04 and $5.68 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 tax basis of oil and gas properties and availability of 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:

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	Year Ended December 31,		
	2006	2005	2004
	(In thousands)		
Changes due to current-year operations -			
Sales of oil and natural gas, net of oil and natural gas operating expenses	$ (72,077)	$ (65,445)	$ (42,982)
Extensions and discoveries	139,657	130,721	80,933
Purchases of oil and gas properties		6,549	16,467
Changes due to revisions in standardized variables			
Prices and operating expenses	(71,814)	105,819	34,516
Income taxes	16,422	(45,999)	(31,667)
Estimated future development costs	64,166	347	12,951
Revision of quantities	(43,362)	(38,326)	(1,307)
Sales of reserves in place	(15,518)	(1,042)	
Accretion of discount	40,423	20,861	11,485
Production rates, timing and other	(58,527)	36,135	(18,301)
Net change	(630)	149,620	62,095
Beginning of year	299,341	149,721	87,626
End of year	$ 298,711	$ 299,341	$ 149,720

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.

2006	First	Second	Third	Fourth
	(In thousands except per share amounts)			
Revenues	$ 21,917	$ 16,477	$ 20,333	$ 24,218
Costs and expenses, net	15,266	13,906	15,582	19,943
Net income	6,651	2,571	4,751	4,275
Basic net income per share	$ 0.28	$ 0.11	$ 0.19	0.17
Diluted net income per share	$ 0.27	$ 0.10	$ 0.18	0.16

2005	First	Second	Third	Fourth
	(In thousands except per share amounts)			
Revenues	$ 15,249	$ 16,351	$ 18,442	$ 28,113
Costs and expenses, net	14,767	11,815	26,359	14,580

Net income (loss)	482	4,536	(7,917)	13,533
Basic net income (loss) per share	$ 0.02	$ 0.20	$ (0.33)	$ 0.56
Diluted net income (loss) per share	$ 0.02	$ 0.19	$ (0.33)	$ 0.54

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SIGNATURES

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

CARRIZO OIL & GAS, INC.

By: /s/ Paul F. Boling

Paul F. Boling
Chief Financial Officer, Vice President,
Secretary and Treasurer

Date: March 30, 2007

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 30, 2007
/s/ Paul F. Boling Paul F. Boling	Chief Financial Officer, Vice President, Secretary and Treasurer (Principal Financial Officer and Principal Accounting Officer)	March 30, 2007
/s/ Steven A. Webster Steven A. Webster	Chairman of the Board	March 30, 2007
/s/ Thomas L. Carter, Jr. Thomas L. Carter, Jr.	Director	March 30, 2007
/s/ Paul B. Loyd, Jr. Paul B. Loyd, Jr.	Director	March 30, 2007
/s/ F. Gardner Parker F. Gardner Parker	Director	March 30, 2007
/s/ Roger A. Ramsey Roger A. Ramsey	Director	March 30, 2007
/s/ Frank A. Wojtek Frank A. Wojtek	Director	March 30, 2007

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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	Amended and Restated Bylaws of the Company, as amended by Amendment No. 1 (incorporated herein by reference to Exhibit 3.2 to the Company s Registration Statement on Form 8-A (Registration No. 000-22915) Amendment No. 2 (incorporated herein by reference to Exhibit 3.2 to the Company s Current Report on Form 8-K dated December 15, 1999) and Amendment No. 3 (incorporated herein by reference to Exhibit 3.1 to the Company s Current Report on Form 8-K dated February 20, 2002).
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).
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).

Exhibit Number	Description
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).
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	Employment Agreement between the Company and Jack Bayless (incorporated herein by reference to Exhibit 10.5 to the Company s Current Report on Form 8-K filed on January 27, 2006).
10.26	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).
10.27	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).
10.28	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).
10.29	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).
10.30	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).
10.31	Employee Restricted Stock Award under the Incentive Plan of Carrizo Oil & Gas, Inc. granted to Jack Bayless effective January 23, 2006 (incorporated herein by reference to Exhibit 10.7 to the Company s Current Report on Form 8-K filed on January 27, 2006).
10.32	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).
10.33	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).
10.34	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).
10.35	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)).
10.36	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)).
10.37	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).

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Exhibit Number	Description
10.38	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).
10.39	Purchase and Sale Agreement by and between Rocky Mountain Gas, Inc. and CCBM, Inc., dated June 29, 2001 (incorporated herein by reference to Exhibit 10.1 to the Company s Quarterly Report on Form 10-Q for the quarter ended June 30, 2001).
10.40	Contribution and Subscription Agreement dated June 23, 2003 by and among Pinnacle Gas Resources, Inc., CCBM, Inc., Rocky Mountain Gas, Inc. and the CSFB Parties listed therein (incorporated herein by reference to Exhibit 10.1 to the Company s Quarterly Report on Form 10-Q for the quarter ended June 30, 2003).
10.41	Amendment to Contribution and Subscription Agreement dated as of August 9, 2005 among Pinnacle Gas Resources, Inc., CCBM, Inc., U.S. Energy Corp., Crested Corp. and the CSFB Parties referred to therein (incorporated herein by reference to Exhibit 10.35 to the Annual Report on Form 10-K for the year ended December 31, 2005).
10.42	Second Amendment to Contribution and Subscription Agreement dated as of March 31, 2006 among Pinnacle Gas Resources, Inc., CCBM, Inc., U.S. Energy Corp., Crested Corp. and the CSFB Parties referred to therein (incorporated herein by reference to Exhibit 10.2 to the Company s Quarterly Report on Form 10-Q for the quarter ended March 31, 2006).
10.43	Second Amended and Restated Credit Agreement dated as of September 30, 2004 by and among Carrizo Oil & Gas, Inc., CCBM, Inc., Hibernia National Bank, as Agent, Union Bank of California, N.A., as co-agent, and Hibernia National Bank and Union Bank of California, N.A., as lenders (incorporated herein by reference to Exhibit 10.1 to the Company s Current Report on Form 8-K filed on October 6, 2004).
10.44	First Amendment to Second Amended and Restated Credit Agreement dated as of October 29, 2004 among Carrizo Oil & Gas, Inc., CCBM, Inc., Hibernia National Bank and Union Bank of California, N.A. (incorporated herein by reference to Exhibit 10.6 to the Company s Current Report on Form 8-K filed on November 3, 2004).
10.45	Commercial Guaranty made and entered into as of September 30, 2004 by CCBM, Inc. in favor of Hibernia National Bank, as agent (incorporated herein by reference to Exhibit 10.2 to the Company s Current Report on Form 8-K filed on October 6, 2004).
10.46	Amended and Restated Stock Pledge and Security Agreement dated and effective as of September 30, 2004 by Carrizo Oil & Gas, Inc. in favor of Hibernia National Bank, as agent (incorporated herein by reference to Exhibit 10.3 to the Company s Current Report on Form 8-K filed on October 6, 2004).
10.47	Second Amendment dated of as April 27, 2005 to the Second Amended and Restated Credit Agreement dated as of October 29, 2004 among Carrizo Oil & Gas, Inc. CCBM, Inc., Hibernia National Bank and Union Bank of California, N.A. (incorporated herein by

	reference to Exhibit 10.1 to the Company s Current Report on Form 8-K filed on May 3, 2005).
10.48	Third Amendment dated as of July 21, 2005 to the Second Amended and Restated Credit Agreement dated as of October 29, 2004 among Carrizo Oil & Gas, Inc., CCBM, Inc., Hibernia National Bank and Union Bank of California, N.A. (incorporated herein by reference to Exhibit 10.4 to the Company s Current Report on Form 8-K filed on July 22, 2005).
10.49	Second Lien Agreement dated as of July 21, 2005 among Carrizo Oil & Gas, Inc., CCBM, Inc., and the lenders named therein and Credit Suisse, as collateral agent and administrative agent (incorporated herein by reference to Exhibit 10.1 to the Company s Current Report on Form 8-K filed on July 22, 2005).
10.50	Stock Pledge and Security Agreement dated as of July 21, 2005 by Carrizo Oil & Gas, Inc. in favor of Credit Suisse, as collateral agent (incorporated herein by reference to Exhibit 10.2 to the Company s Current Report on Form 8-K filed on July 22, 2005).
10.51	Commercial Guaranty dated as of July 21, 2005 by CCBM, Inc. in favor of Credit Suisse (incorporated herein by reference to Exhibit 10.3 to the Company s Current Report on Form 8-K filed on July 22, 2005).
10.52	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).
10.53	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 Number	Description
	Exhibit 10.2 to the Company s Current Report on Form 8-K filed on May 30, 2006).
10.54	Form of Subscription and Registration Rights Agreement among the Company and the Subscribers named therein (incorporated herein by reference to Exhibit 10.5 to the Company s Quarterly Report on Form 10-Q for the quarter ended June 30, 2006).
10.55	Placement Agent Agreement dated July 25, 2006 between the Company and Johnson Rice & Company L.L.C. (incorporated herein by reference to Exhibit 10.6 to the Company s Quarterly Report on Form 10-Q for the quarter ended June 30, 2006).
10.55	Amendment No.1, effective as of December 19, 2006, to the Second Lien Credit Agreement among Carrizo Oil & Gas, Inc., CCBM, Inc., CLLR, Inc., the Lenders named therein and Credit Suisse, as collateral agent and administrative agent (incorporated herein by reference to Exhibit 10.1 to the Company s Current Report on Form 8-K filed on December 22, 2006).
10.57	First Amendment to Credit Agreement, Consent and Waiver, effective as of December 19, 2006, among Carrizo Oil & Gas, Inc., the Guarantors party thereto, 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 December 22, 2006).
10.58	Director Compensation.
10.59	Base Salaries and 2006 Annual Bonuses 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.
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, 2006.

99.2	Summary of Reserve Report of Fairchild & Wells, Inc. as of December 31, 2006.
99.3	Summary of Reserve Report of LaRoche Petroleum Consultants, Ltd. as of December 31, 2006.

Incorporated by reference as indicated.