CARRIZO OIL & GAS INC
Form S-2/A
January 15, 2004

AS FILED WITH THE SECURITIES AND EXCHANGE COMMISSION ON JANUARY 15, 2004

REGISTRATION NO. 333-111475

UNITED STATES SECURITIES AND EXCHANGE COMMISSION
WASHINGTON, D.C. 20549

AMENDMENT NO. 1

TO

FORM S-2
REGISTRATION STATEMENT UNDER THE SECURITIES ACT OF 1933

CARRIZO OIL & GAS, INC.
(Exact name of registrant as specified in its charter)

TEXAS	14701 ST. MARY'S LANE, SUITE 800	76-04
(State or other jurisdiction of incorporation or organization)	HOUSTON, TEXAS 77079	(I.R.S. Employer I
	(281) 496-1352	

(Address, including zip code, and telephone number, including area code, of registrant's principal executive offices)

S.P. JOHNSON IV
PRESIDENT AND CHIEF EXECUTIVE OFFICER
CARRIZO OIL & GAS, INC.
14701 ST. MARY'S LANE, SUITE 800
HOUSTON, TEXAS 77079
(281) 496-1352
(Name, address, including zip code, and telephone number, including area code, of agent for service)

COPIES TO:

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HOUSTON, TEXAS 77002-4995 HOUSTON, TEXAS 77002
(713) 229-1234 (713) 758-2222

APPROXIMATE DATE OF COMMENCEMENT OF PROPOSED SALE TO THE PUBLIC: Upon the effective date of this registration statement.

If any of the securities being registered on this Form are to be offered on a delayed or continuous basis pursuant to Rule 415 under the Securities Act of 1933, check the following box. [ ]

If the registrant elects to deliver its latest annual report to security holders, or a complete and legal facsimile thereof, pursuant to Item 11(a)(1) of this Form, check the following box. [ ]

If this Form is filed to register additional securities for an offering pursuant to Rule 462(b) under the Securities Act, please check the following box and list the Securities Act registration statement number of the earlier effective registration statement for the same offering. [ ]

If this Form is a post-effective amendment filed pursuant to Rule 462(c) under the Securities Act, check the following box and list the Securities Act registration statement number of the earlier effective registration statement for the same offering. [ ]

If this Form is a post-effective amendment filed pursuant to Rule 462(d) under the Securities Act, check the following box and list the Securities Act registration statement number of the earlier effective registration statement for the same offering. [ ]

If delivery of the prospectus is expected to be made pursuant to Rule 434, please check the following box. [ ]

THE REGISTRANT HEREBY AMENDS THIS REGISTRATION STATEMENT ON SUCH DATE OR DATES AS MAY BE NECESSARY TO DELAY ITS EFFECTIVE DATE UNTIL THE REGISTRANT SHALL FILE A FURTHER AMENDMENT WHICH SPECIFICALLY STATES THAT THIS REGISTRATION STATEMENT SHALL THEREAFTER BECOME EFFECTIVE IN ACCORDANCE WITH SECTION 8(a) OF THE SECURITIES ACT OF 1933 OR UNTIL THIS REGISTRATION STATEMENT SHALL BECOME EFFECTIVE ON SUCH DATE AS THE COMMISSION, ACTING PURSUANT TO SAID SECTION 8(a), MAY DETERMINE.

SUBJECT TO COMPLETION, DATED JANUARY 15, 2004

THE INFORMATION CONTAINED IN THIS PROSPECTUS IS NOT COMPLETE AND MAY BE CHANGED. THESE SECURITIES MAY NOT BE SOLD UNTIL THE REGISTRATION STATEMENT FILED WITH THE SECURITIES AND EXCHANGE COMMISSION IS EFFECTIVE. THIS PROSPECTUS IS NOT AN OFFER TO SELL THESE SECURITIES AND IT IS NOT SOLICITING AN OFFER TO BUY THESE SECURITIES IN ANY STATE WHERE THE OFFER OR SALE IS NOT PERMITTED.

5,700,000 SHARES

(CARRIZO OIL & GAS, INC. LOGO)
COMMON STOCK
$ PER SHARE

Carrizo Oil & Gas, Inc. is offering 3,420,000 shares of common stock and the selling shareholders identified in this prospectus are offering 2,280,000 shares of common stock.

The common stock is listed on the Nasdaq National Market under the symbol "CRZO." On January , 2004, the last reported sales price of the common stock listed on the Nasdaq National Market was $ per share.

INVESTING IN THE COMMON STOCK INVOLVES RISKS. SEE "RISK FACTORS" BEGINNING ON PAGE 10.

	PER SHARE	TOTAL
Price to the public..	$	$
Underwriting discount......................................		
Proceeds to Carrizo Oil & Gas, Inc.........................		
Proceeds to the selling shareholders.......................		

We and our selling shareholders have granted an over-allotment option to the underwriters. Under this option, the underwriters may elect to purchase a maximum of 855,000 additional shares (256,500 shares from us and 598,500 shares from the selling shareholders) within 30 days following the date of this prospectus to cover over-allotments.

NEITHER THE SECURITIES AND EXCHANGE COMMISSION NOR ANY STATE SECURITIES COMMISSION HAS APPROVED OR DISAPPROVED OF THESE SECURITIES OR DETERMINED IF THIS PROSPECTUS IS TRUTHFUL OR COMPLETE. ANY REPRESENTATION TO THE CONTRARY IS A CRIMINAL OFFENSE.

CIBC WORLD MARKETS
FIRST ALBANY CAPITAL
HIBERNIA SOUTHCOAST CAPITAL
JOHNSON RICE & COMPANY L.L.C.

The date of this prospectus is , 2004.

[INSIDE FRONT COVER]

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PROSPECTUS SUMMARY

This summary highlights certain material information contained or incorporated by reference in this prospectus. You should read carefully the entire prospectus and the documents incorporated by reference in this prospectus. Unless the context otherwise requires, all references to "Carrizo," "we," "us," and "our" refer to Carrizo Oil & Gas, Inc. and its subsidiaries. The term "you" refers to a prospective investor. We have included definitions of technical terms and abbreviations important to an understanding of our business under "Glossary of Certain Oil and Gas Terms" beginning on page 74. Unless explicitly stated otherwise, or the context otherwise requires, all references in this prospectus to planned capital expenditures or planned drilling activities assume the completion of this offering.

ABOUT US

We are 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 in Texas and Louisiana, primarily in the Miocene, Wilcox, Frio and Vicksburg trends. Our other interests include properties in East Texas, a coalbed methane investment in the Rocky Mountains and, recently, the Barnett Shale trend in North Texas. Additionally, in 2003 we obtained licenses to explore in the U.K. North Sea.

We have grown our production through our 3-D seismic-driven exploratory drilling program. Our compound production growth rate for the period December 31, 1999 through September 30, 2003 on an annualized basis was 19%. From our inception through September 30, 2003, we participated in the drilling of 285 wells (88.0 net) with a success rate of approximately 67% in our onshore Gulf Coast core area. Exploratory wells accounted for 97% of the total wells we drilled. Based on the reports of our independent reserve engineers, our total proved reserves as of December 31, 2002 were an estimated 63.2 Bcfe with a PV-10 Value of $83.6 million. During 2002, we added 11.4 Bcfe to proved reserves and produced 7.2 Bcfe.

As a main component of our business strategy, we have acquired licenses for over 8,700 square miles of 3-D seismic data for processing and evaluation. Since 2001, we have been able to increase the size of our 3-D seismic holdings in our onshore Gulf Coast core area by approximately 75% to over 6,650 square miles, in large part by taking advantage of very favorable pricing available for nonproprietary data. 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, ARCO, Conoco, Vastar Resources, Pennzoil and Tenneco. Using 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 September 30, 2003, we had 85,678 gross acres in Texas and Louisiana under lease or lease option, almost all of which is covered by 3-D seismic data. On this leased acreage, we have identified over 120 potential exploratory drilling locations, including over 45 additional extension opportunities, depending on the success of our initial drilling activities on those locations. The vast majority of our 3-D seismic data covers productive geological trends in our onshore Gulf Coast core area, where we have made 192 completions as a result of our utilization and evaluation of this data.

In 2003, we expect capital expenditures to have been $25.3 million, which were used primarily to drill 38 wells (10.1 net). In 2004, we expect capital expenditures to be approximately $40 to $45 million (a 58 to 78% increase over our expected 2003 capital expenditures). We expect to drill 38 wells in 2004 (18.5 net), 30 of which we plan to operate and substantially all of which we anticipate will be exploratory wells. We anticipate that approximately 97% of our drilling capital expenditures will be directed toward our core onshore Gulf Coast area. We expect that the proceeds of this offering will allow us to accelerate and enable us to retain a larger working interest in our drilling program. Our drilling program may be revised

substantially over time depending on a number of factors, including the results of our exploration efforts, the availability of sufficient capital resources for the drilling of prospects and economic and industry conditions at the time of drilling.

RECENT DEVELOPMENTS

Fourth Quarter 2003 Operating Results

During the fourth quarter of 2003, in our core areas in the onshore Gulf Coast of Texas and Louisiana, we participated in the drilling of 11 gross exploratory wells, ten of which were successful. Also during the quarter, in our Barnett Shale Project we participated in the drilling of two gross (one net) exploratory wells and two gross (one net) development wells, all of which were successful. On a combined basis for these two areas, we had a 93.3% success rate for the quarter.

Production during the fourth quarter of 2003 was estimated at 1.85 Bcfe, bringing our 2003 annual production to an estimated record level of 7.5 Bcfe, an increase of 3.5% over our 2002 production level. Approximately 72% of our production during the fourth quarter of 2003 and 64% of our production in the full year 2003 was natural gas. We estimate that fourth quarter 2003 sales prices, including the effect of hedging activities, averaged approximately $4.78 per Mcf and $29.61 per barrel. Based on our preliminary reserve estimates, we believe that in 2003 we more than replaced our production with proved reserve additions from our drilling activities.

Potential Barnett Shale Acquisition

We have entered into negotiations with a private company to purchase working interests and acreage in certain oil and gas wells located in Denton County, Texas in the Newark East Field in the Barnett Shale trend in proximity to our existing operations. This potential acquisition, with an expected purchase price of $7.2 million, includes non-operated working interests ranging from 12.5% to 45% over 3,800 acres. As of January 1, 2004, the 14 producing wells (5.0 net) that would be included in the acquisition were producing a net 1.4 MMcf/d with another five wells (1.3 net) waiting for pipeline hook-up. We expect the undeveloped acreage to contribute additional drilling locations, 13 of which will target proved undeveloped reserves and 18 of which will be exploratory.

We expect that we would finance the acquisition with our current revolving credit facility or, alternatively, with a new project financing facility that we would seek to obtain. We currently have targeted a closing date of February 16, 2004 for the acquisition. There can be no assurance that the transaction described above will be completed on the terms or timing described above or at all. Regardless of whether this transaction is completed, we intend to continue to pursue growth opportunities in this geologic trend.

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;\
- focus on prolific and industry-proven trends;

- aggressively evaluate 3-D seismic data and acquire acreage to maintain a large drillsite inventory;

- maintain a balanced exploration drilling portfolio;

- manage risk exposure by market testing prospects and optimizing working interests; and

- retain and incentivize a highly qualified technical staff.

Through the execution of this business strategy, we have achieved the following results from January 1, 2000 through December 31, 2003:

- we drilled 117 wells in our onshore Gulf Coast area, 107 of which were classified as exploratory wells, with a 77% success rate; and

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- our annual production grew from 4.3 Bcfe in 1999 to 7.5 Bcfe in 2003, a compound annual growth rate of approximately 15%.

In addition, we have achieved the following results over the three years ended December 31, 2002:

- our average annual reserve replacement percentage was 222% and;

- our proved reserves grew from 40.6 Bcfe at December 31, 1999 to 63.2 Bcfe at December 31, 2002, a compound annual growth rate of 16%.

AREAS OF OPERATIONS

Our operations are focused primarily in the onshore Gulf Coast extending from South Louisiana to South Texas. Our other areas of interest are in East Texas, the Barnett Shale trend, the Rocky Mountains and the U.K. North Sea. The table below highlights our main areas of activity:

	THREE MONTHS ENDED SEPTEMBER 30, 2003		AT SEPTEMBER 30, 2003			
	AVERAGE DAILY NET PRODUCTION (MMCFE/D)	% NAT. GAS	PRODUCTIVE WELLS GROSS	PRODUCTIVE WELLS NET	3-D SEISMIC DATA (SQ. MILES)	NET OPTIONS/ LEASED ACRES
Wilcox...............	1.6	94%	28	8.2	1,793	18,741
Frio/Vicksburg.......	8.4	58%	137	43.3	2,102	8,615

Southeast Texas......	8.8	78%	11	3.8	900	3,729
South Louisiana......	2.4	58%	7	1.3	1,864	2,028
Other................	0.4	-	-	-	2,078	240,978
Total..............	21.6	68%	183	56.6	8,737	274,091

Onshore Gulf Coast

We divide our onshore Gulf Coast core region into four main producing areas: Wilcox, Frio/Vicksburg, Southeast Texas and South Louisiana. Our onshore Gulf Coast core area generally contains geologically complex natural gas objectives well-suited for drilling using 3-D seismic evaluation. From our inception through December 31, 2003, we have acquired licenses for over 6,650 square miles of 3-D seismic data and have drilled 285 wells with a success rate of 67% in this area. We believe that our high level of success is based primarily on our exploration approach and our staff's extensive experience in this area.

In our onshore Gulf Coast area, we have identified over 120 exploratory drilling opportunities on acreage we have under lease or have an option to lease, including over 45 additional extension opportunities, depending on the success of our initial drilling activities on those locations. Currently, we plan to drill 36 wells (16.6 net) in the onshore Gulf Coast area in 2004.

- Wilcox Trend of Texas. We have acquired licenses for approximately 1,800 square miles of 3-D seismic data that covers potential Wilcox formation exploration and development targets. From January 1, 2000 through December 31, 2003, we drilled 40 wells (13.3 net) with a success rate of 80% in this area. We have identified over 30 potential exploratory drilling locations, with over 22 additional potential extension locations depending on the success of our initial drilling activities, on our leased acreage. As of December 31, 2003, we had an average working interest on producing wells of 32.5% and operated 24 wells in this area.

- Frio/Vicksburg Trends of Texas. We have acquired licenses for approximately 2,100 miles of 3-D seismic data over the Frio, Vicksburg and Yegua sands. From January 1, 2000 through December 31, 2003, we drilled 45 wells (11.6 net) with a success rate of 84% in this area. We have identified over 23 potential exploratory drilling locations, with over 12 additional potential extension

locations depending on the success of our initial drilling activities, on our leased acreage. As of December 31, 2003, we had an average working interest on producing wells of 27.5% and operated 15 wells in this area.

- Southeast Texas. We have acquired licenses for approximately 900 square miles of 3-D seismic data, including approximately 425 square miles of newly released data delivered in 2003, over our Southeast Texas project areas which are focused primarily on 3-D seismic anomalies in the Frio, Yegua, Cook Mountain and Vicksburg formations. From January 1, 2000 through December 31, 2003, we drilled 17 wells (4.8 net) with a success rate of 71% in this area. We have identified over 15 potential exploratory drilling locations, with 10 additional potential extension locations depending on the success of our initial drilling activities, on our leased acreage. As of December 31, 2003, we had an average working interest on producing wells of 34.7% and we operated 13 wells in this area.

- South Louisiana. We have acquired licenses for approximately 1,850 square miles of 3-D seismic data, including approximately 630 square miles of newly released data delivered in 2003, that covers potential Upper Miocene geologic interval exploration and development targets. From January 1, 2000 through December 31, 2003, we drilled 14 wells (2.4 net) with a success rate of 50% in this area. We have identified eight potential exploratory drilling locations, with three additional potential extension locations depending on the success of our initial drilling activities, on our leased acreage. As of September 30, 2003, we had an average working interest on producing wells of 24.2% and operated four wells in this area.

Other Areas of Interest

Our other areas of interest are contained in:

- East Texas, where we have our Camp Hill heavy oil project and our Tortuga Grande Cotton Valley prospect;

- the Barnett Shale trend in North Texas, a new area of interest in 2003 on which we have acquired leases on over 2,100 net acres and have participated in the drilling of four wells (1.6 net) as of October 31, 2003;

- coalbed methane interests in the Rocky Mountains, largely related to our minority interest in Pinnacle Gas Resources, Inc., a corporate joint venture formed with an affiliate of Credit Suisse First Boston in 2003; and

- our recently obtained offshore licenses to explore on approximately 210,000 acres in the U.K. North Sea, which we plan to promote to third parties and for which our estimated project commitments from commencement through mid-2005 are $0.9 million.

For 2004, we expect to spend less than $2.0 million total in these areas. We believe that each of these areas has significant potential for us. We may, in the future, either allocate a larger portion of our capital expenditures for development of these interests or sell down or otherwise dispose of these interests.

OUR EXECUTIVE OFFICES

Our executive offices are located at 14701 St. Mary's Lane, Suite 800, Houston, Texas 77079, and our telephone number is (281) 496-1352. Information contained on our website, www.carrizo.cc, is not part of this prospectus.

THE OFFERING

Common stock offered by us............. 3,420,000 shares(a)

Common stock offered by the selling shareholders...........................	2,280,000 shares(b)
Common stock to be outstanding after this offering..........................	18,010,015 shares(a)(c)
Use of proceeds........................	We intend to use the proceeds from this offering to accelerate our drilling program and to retain larger interests in portions of our drilling prospects that we otherwise would have sold down or for which we would have sought partners, and for general corporate purposes. Pending such use, we intend to use a portion of the net proceeds to repay the outstanding principal amount under our revolving credit facility. See "Use of Proceeds."
Nasdaq National Market Symbol...........	CRZO

(a) Does not include 256,500 shares that may be sold upon exercise of the underwriters' over-allotment option granted by us.
(b) Does not include 598,500 shares that may be sold upon exercise of the underwriters' over-allotment option granted by the selling shareholders.
(c) Based on shares outstanding as of November 30, 2003. The number of shares of common stock to be outstanding after this offering also does not include 6,103,434 shares of our common stock reserved for issuance upon the exercise of options and warrants and upon the conversion of preferred stock previously issued.

Unless otherwise stated, all information contained in this prospectus assumes no exercise of the over-allotment option granted to the underwriters.

RISK FACTORS

You should consider carefully the "Risk Factors" beginning on page 10 of this prospectus before making an investment in our common stock.

SUMMARY HISTORICAL FINANCIAL DATA

This section presents our summary historical financial data. This data should be read in conjunction with the consolidated financial statements, related notes and other financial information included and incorporated by reference herein. The summary historical consolidated financial data is not intended to replace the consolidated financial statements.

We derived the statement of operations data and statement of cash flows data for the years ended December 31, 2000, 2001 and 2002, and balance sheet data as of December 31, 2001 and 2002 from the audited financial statements included in this prospectus and the balance sheet data as of December 31, 2000 from audited consolidated financial statements that are not included in this prospectus. We derived the statement of operations data and statement of cash flows data for the nine months ended September 30, 2002 and 2003 and the balance sheet data as of September 30, 2002 and 2003 from the unaudited consolidated financial statements included in this prospectus. The unaudited consolidated financial statements include all adjustments, consisting of normal recurring accruals, which we consider necessary for a fair presentation of our financial position and results of operations for these periods. The financial statements as of and for the year ended December 31, 2002 were audited by Ernst & Young LLP, independent auditors. The financial statements as of and for the years ended December 31, 2000 and 2001 were audited by Arthur Andersen LLP. In 2002, we dismissed Arthur Andersen LLP as our independent public accountants and retained Ernst & Young LLP to act as our independent auditors.

	YEAR ENDED DECEMBER 31,			NINE MONTHS ENDED SEPTEMBER 30,	
	2000	2001	2002	2002	2003
	(in thousands, except per share data)				
STATEMENT OF OPERATIONS DATA:					
Oil and natural gas revenues	$ 26,834	$ 26,226	$ 26,802	$ 17,559	$ 29,615
Cost and expenses:					
Oil and natural gas operating expenses	4,941	4,138	4,908	3,687	5,071
Depreciation, depletion and amortization	7,170	6,492	10,574	7,332	8,727
General and administrative	3,143	3,333	4,133	3,049	4,303
Stock option compensation	652	(558)	(84)	(70)	319
Total costs and expenses	15,906	13,405	19,531	13,998	18,420
Operating income	10,928	12,821	7,271	3,561	11,195
Equity loss of Pinnacle Gas Resources	-	-	-	-	(177)
Interest income (net of amounts capitalized and interest expense)	579	269	54	44	34
Other income, net	1,482	1,777	274	245	14
Income before income taxes	12,989	14,867	7,599	3,850	11,066
Income tax expense	1,004	5,336	2,809	1,456	4,053
Net income before cumulative effect of change in accounting principle	11,985	9,531	4,790	2,394	7,013
Dividends and accretion on preferred stock	-	-	588	415	552
Cumulative effect of change in accounting principle	-	-	-	-	128
Net income available to common shareholders	$ 11,985	$ 9,531	$ 4,202	$ 1,979	$ 6,333

	YEAR ENDED DECEMBER 31,			NINE MONTHS ENDED SEPTEMBER 30,	
	2000	2001	2002	2002	2003
	(in thousands, except per share data)				
Earnings per common share					
Basic	$ 0.85	$ 0.68	$ 0.30	$ 0.14	$ 0.45
Diluted	0.74	0.57	0.26	0.12	0.38
Weighted average shares outstanding					
Basic	14,028	14,059	14,158	14,152	14,225
Diluted	16,256	16,731	16,148	15,928	16,574
STATEMENT OF CASH FLOWS DATA:					
Net cash provided (used) by:					
Operating activities	$ 17,133	$ 23,951	$ 19,925	$ 12,339	$ 23,509
Investing activities	(16,438)	(31,224)	(24,100)	(16,744)	(19,028)
Financing activities	(3,823)	2,292	5,682	3,967	(4,798)

	AS OF DECEMBER 31,			AS OF SEPTEMBER 30,	
	2000	2001	2002	2002	2003
	(in thousands)				
BALANCE SHEET DATA:					
Working capital	$ 6,433	$ (582)	$ (1,442)	$ (4,815)	$ (4,599)
Property and equipment, net	72,129	104,132	120,526	117,780	124,030
Total assets	93,000	117,392	135,388	131,630	147,635
Long-term debt, including current maturities	34,556	38,188	42,012	37,415	36,421
Convertible participating preferred stock	-	-	6,373	6,045	6,925
Shareholders' equity	52,939	63,204	66,816	64,603	74,069

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SUMMARY RESERVE AND PRODUCTION DATA

The following table sets forth summary information concerning our estimated proved natural gas and oil reserves at December 31, 2000, 2001 and 2002 based on reports prepared by Ryder Scott Company and Fairchild and Wells, Inc., Independent Petroleum Engineers. The PV-10 Value and the Standardized Measure attributable to our proved reserves, shown below, use prices and costs in effect as of December 31 of the year for which such information is presented. For more information regarding our natural gas and oil reserves, please read "Business and Properties--Natural Gas and Oil Reserves."

	AT DECEMBER 31,		
	2000	2001	2002

ESTIMATED NET PROVED RESERVES:			
Natural gas (MMcf)	10,992	17,858	12,922
Oil (MBbls)	6,397	6,857	8,381
Natural gas equivalent (MMcfe)	49,377	59,000	63,208
PV-10 Value (in thousands)(1)	$88,830	$49,582	$83,614
Standardized Measure (in thousands)	$70,106	$44,577	$65,297
PRICES USED IN CALCULATING ESTIMATED VALUE OF PROVED RESERVES:			
Natural gas (per Mcf)	$ 10.34	$ 2.76	$ 4.70
Oil (per Bbl)	24.85	17.71	29.16
OTHER RESERVE DATA:			
Average all-sources finding cost (per Mcfe)(2)	$ 1.01	$ 1.97	$ 1.89
Average reserve replacement percentage	241%	279%	163%
Proved developed reserves (MMcfe)	16,452	20,702	21,184

Our average all-sources finding cost for the three years ended December 31, 2002 was $1.59 per Mcfe.

The following table sets forth summary information concerning our production results, sales prices and costs and expenses for the years ended December 31, 2000, 2001 and 2002 and for the nine-month periods ended September 30, 2002 and 2003.

	YEAR ENDED			NINE MONTHS ENDED SEPTEMBER 30,	
	2000	2001	2002	2002	2003
NET PRODUCTION VOLUME:					
Oil (MBbls)	198	160	401	261	363
Natural gas (MMcf)	5,460	4,432	4,801	3,543	3,432
Natural gas equivalent (MMcfe)	6,651	5,390	7,207	5,109	5,607
AVERAGE PRE-HEDGE SALES PRICES:					
Oil (per Bbl)	$28.64	$24.14	$25.63	$23.95	$31.02
Natural gas (per Mcf)	4.15	4.58	3.62	3.32	5.87
AVERAGE POST-HEDGE SALES PRICES:					
Oil (per Bbl)	$27.81	$24.28	$24.94	$23.34	$29.08
Natural gas (per Mcf)	3.90	5.04	3.50	3.24	5.56
COSTS AND EXPENSES (PER MCFE):					
Oil and natural gas operating expenses	$ 0.74	$ 0.77	$ 0.68	$ 0.72	$ 0.90
Depreciation, depletion and amortization	1.08	1.20	1.47	1.44	1.56
General and administrative	0.47	0.62	0.57	0.60	0.77

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(1) The PV-10 Values are pre-tax and were determined by using the year-end sales prices, which averaged $24.85, $17.71 and $29.16 per Bbl of oil, and $10.34, $2.76 and $4.70 per Mcf of natural gas in 2000, 2001 and 2002, respectively.

(2) Our all-sources finding cost excludes the coalbed methane unproved property costs we contributed as a minority investment to Pinnacle Gas Resources, Inc. in June 2003 and, accordingly, is no longer included in our consolidated operations. We believe our calculation of finding cost

provides investors with an indication of our relative exploration efficiency. In addition, our management uses finding cost as a component of our individual well economic analysis. 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 $3.6 million, $3.2 million and $3.1 million for the years ended December 31, 2000, 2001 and 2002, respectively:

	YEAR ENDED DECEMBER 31,		
	2000	2001	2002
	(in thousands, except finding co		
Acquisition costs:			
Unproved properties contributed to Pinnacle	--	$ 5,239	$ 1,3
Other unproved properties	$ 6,641	7,368	5,0
Proved properties	337	800	6
Exploration	7,843	18,356	14,1
Development	1,361	3,065	2,3
Total costs incurred	$16,182	$34,828	$23,6
Less unproved properties contributed to Pinnacle	--	$ 5,239	$ 1,3
Adjusted costs	$16,182	$29,589	$22,2
Total proved reserves added	16,040	15,018	11,7
Average all-sources finding cost (per Mcfe)	$ 1.01	$ 1.97	$ 1.

RISK FACTORS

You should consider carefully the following risk factors, in addition to the other information set forth in this prospectus, before purchasing shares of our common stock. Each of these risk factors could adversely affect our business, operating results and financial condition, as well as the value of an investment in our common stock. An investment in our common stock includes a high degree of risk.

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 prospectus.

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 numerous 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 prospectus 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. The reserve data included or incorporated by reference in this prospectus represents estimates that depend on a number of factors and assumptions that may vary considerably from actual results, including:

- historical production from the area compared with production from other areas;

- the assumed effects of regulations by governmental agencies;

- assumptions concerning future natural gas and oil prices;

- future operating costs;

- severance and excise taxes;

- development costs; and

- workover and remedial costs.

For these reasons, estimates of the economically recoverable quantities of natural gas and oil attributable to any particular group of properties, classifications of those reserves based on risk of recovery and estimates of the future net cash flows expected from them prepared by different engineers or by the same engineers but at different times may vary substantially. 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.

As of December 31, 2002, approximately 66% of our proved reserves were either proved undeveloped or proved nonproducing. Moreover, some of the producing wells included in our reserve reports as of December 31, 2002 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 discounted future net cash flows included or incorporated by reference in this prospectus are not necessarily the same as the current market value of our estimated natural gas and oil reserves. As required by the Securities and Exchange Commission (the SEC), 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 in 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. The business of exploring for, developing or acquiring reserves is capital intensive. Recovery of our reserves, particularly undeveloped reserves, will require significant additional capital expenditures and successful drilling operations. To the extent cash flow from operations is reduced and external sources of capital become limited or unavailable, our ability to make the necessary capital investment to maintain or expand our asset base of natural gas and oil reserves would be impaired. 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;
- overall economic conditions;
- weather conditions;
- domestic and foreign governmental relations;
- 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 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

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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. We may not be able to conduct our operations, evaluate and select suitable properties and consummate transactions successfully in this highly competitive environment.

WE MAY NOT BE ABLE TO KEEP PACE WITH TECHNOLOGICAL DEVELOPMENTS IN OUR INDUSTRY.

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

WE ARE SUBJECT TO VARIOUS GOVERNMENTAL REGULATIONS AND ENVIRONMENTAL RISKS.

Natural gas and oil operations are subject to various federal, state 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 the issuance of new coalbed methane drilling permits, which have been halted temporarily pending a final Record of Decision for Montana's Environmental Impact Statement. 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.

WE MAY NOT HAVE ENOUGH INSURANCE TO COVER ALL OF THE RISKS WE FACE.

In accordance with customary industry practices, we maintain insurance coverage against some, but not all, potential losses in order to protect against the risks we face. We do not carry business interruption insurance. We may elect not to carry insurance if our 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 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 Chief Financial Officer, Jeremy T. Greene, our Vice President of Exploration Development, Kendell A. Trahan, our Vice President of Land, and J. Bradley Fisher, our Vice President of Operations. 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 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 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 HEDGE THE PRICE RISKS ASSOCIATED WITH OUR PRODUCTION. OUR HEDGE TRANSACTIONS MAY RESULT IN OUR MAKING CASH PAYMENTS OR PREVENT US FROM BENEFITTING TO THE FULLEST EXTENT POSSIBLE 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 hedging 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. 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.

OUR CREDIT FACILITY CONTAINS OPERATING RESTRICTIONS AND FINANCIAL COVENANTS, AND WE MAY HAVE DIFFICULTY OBTAINING ADDITIONAL CREDIT.

Over the past few years, increases in commodity prices and 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 facility is secured by a pledge of substantially all of our producing natural gas and oil properties assets, is guaranteed by our subsidiary and contains covenants that limit additional borrowings, dividends to nonpreferred shareholders, the incurrence of liens, investments, sales or pledges of assets, changes in control, repurchases or redemptions for cash of our common or preferred stock, speculative commodity transactions and other matters. The credit facility also requires that specified financial ratios be maintained. We may not be able to refinance our debt or obtain additional financing, particularly in view of our current credit agreement's restrictions on our ability to incur debt under our bank credit facility and the fact that substantially all of our assets are currently pledged to secure obligations under that facility. The restrictions of our credit facility and our difficulty in obtaining additional debt financing may have adverse consequences on our operations and financial results including:

- our ability to obtain financing for working capital, capital expenditures, our drilling program, purchases of new technology or other purposes may be impaired;

- the covenants in our 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 generally.

We may incur additional debt in order to fund our exploration and development activities. A higher level of indebtedness increases the risk that we may default on our debt obligations. Our ability to meet our debt obligations and reduce our level of indebtedness depends on future performance. General economic conditions, natural gas and oil prices and financial, business and other factors, many of which are beyond our control, affect our operations and our future performance. Our senior subordinated notes contain restrictive covenants similar to those under our credit facility.

In addition, under the terms of our credit facility, our borrowing base is subject to redeterminations at least semiannually 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.

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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.

OUR AFFILIATES CONTROL A MAJORITY OF OUR OUTSTANDING COMMON STOCK, WHICH MAY AFFECT YOUR VOTE AS A SHAREHOLDER.

As of November 30, 2003, our officers and directors and their affiliates beneficially owned approximately 84% of our outstanding common stock (68% after this offering). As a result, these shareholders, to the extent they act as a group, will be able to significantly influence or control the outcome of certain matters requiring a shareholder vote, including votes concerning the election of directors, the adoption or amendment of provisions in our certificate of incorporation or bylaws, and the approval of mergers and other significant corporate transactions. The existence of these levels of ownership concentrated in a few persons makes it unlikely that any other holder of common stock will be able to affect our management or strategic direction. These factors may also have the effect of delaying, deterring or preventing a change in control and may adversely affect the voting and other rights of other shareholders.

OUR SHARES THAT ARE ELIGIBLE FOR FUTURE SALE MAY HAVE AN ADVERSE EFFECT ON THE PRICE OF OUR COMMON STOCK.

Future sales of substantial amounts of our common stock, or a perception that such sales could occur, could adversely affect the market price of our common stock and could impair our ability to raise capital through the sale of our equity securities. The 5.7 million shares of common stock offered hereby will be eligible for immediate sale in the public market without restriction. This risk is compounded by the fact that a substantial portion of our common stock is owned by a relatively few number of individuals or entities. The major holders of shares of our common stock have piggyback and demand registration rights that provide for the registration of the resale of those shares at our expense which will allow those shares to be sold in the public market without restriction. We and our directors and officers and certain of our affiliates have agreed not to offer for sale, sell or otherwise dispose of any shares of our common stock or any securities convertible or exercisable or exchangeable for shares of our common stock, or to exercise demand or piggyback registration rights with respect to those shares, for a period of 90 days after the date of this prospectus, unless the representatives of the underwriters give their prior written consent, subject to certain exceptions. The underwriters may consent at any time and without public notice.

THE MARKET PRICE OF OUR COMMON STOCK IS VOLATILE.

The trading price of our common stock and the price at which we may sell common stock in the future are subject to large fluctuations in response to any of the following:

- limited trading volume in our common stock;
- quarterly variations in operating results;
- our involvement in litigation;
- general financial market conditions;
- the prices of natural gas and oil;
- announcements by us and our competitors;
- our liquidity;

- our ability to raise additional funds;
- changes in government regulations; and
- other events.

WE DO NOT ANTICIPATE PAYING DIVIDENDS ON OUR COMMON STOCK IN THE NEAR FUTURE.

We have not paid any dividends in the past and do not intend to pay cash dividends on our common stock 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. Any future dividend payments will be restricted by the terms of our credit agreement and our senior subordinated notes.

CERTAIN ANTI-TAKEOVER PROVISIONS MAY AFFECT YOUR RIGHTS AS A SHAREHOLDER.

Our articles of incorporation authorize our board of directors to set the terms of and issue additional preferred stock without shareholder approval. Our board of directors could use the preferred stock as a means to delay, defer or prevent a takeover attempt that a shareholder might consider to be in our best interest. In addition, our outstanding Series B preferred stock, our senior credit facility and our senior subordinated notes contain terms that may restrict our ability to enter into change of control transactions, including requirements to redeem or repay the Series B preferred stock, our credit facility and our senior subordinated notes upon a change in control. These provisions, along with specified provisions of the Texas Business Corporation Act and our articles of incorporation and bylaws, may discourage or impede transactions involving actual or potential changes in our control, including transactions that otherwise could involve payment of a premium over prevailing market prices to holders of our common stock.

FORWARD-LOOKING STATEMENTS

This prospectus and the documents included or incorporated by reference in this prospectus contain statements concerning our expectations, beliefs, plans, objectives, goals, strategies, future events or performance and underlying assumptions and other statements that are not historical facts. These statements are "forward-looking statements" within the meaning of the Private Securities Litigation Reform Act of 1995. You generally can identify our forward-looking statements by the words "anticipate," "believe," "budgeted," "continue," "could," "estimate," "expect," "forecast," "goal," "intend," "may," "objective," "plan," "potential," "predict," "projection," "scheduled," "should," "will" or other similar words. These forward-looking statements include, among others, statements regarding:

- our growth strategies;
- our ability to explore for and develop natural gas and oil resources successfully and economically;
- anticipated trends in our business;
- our future results of operations;
- our liquidity and our ability to finance our exploration and development activities;

- future market conditions in the oil and gas industry;

- our ability to make and integrate acquisitions;

- the impact of governmental regulation; and

- future acquisitions.

These statements may be found under "Prospectus Summary," "Risk Factors," "Use of Proceeds," "Management's Discussion and Analysis of Financial Condition and Results of Operations" and "Business and Properties." More specifically, our forward looking statements include:

- our estimates of the timing and number of wells we expect to drill and other exploration activities included in "Business and Properties" and elsewhere in this prospectus; and

- statements regarding our capital expenditure program included in "Management's Discussion and Analysis of Financial Condition and Results of Operations" and elsewhere in this prospectus.

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

Some of the factors that could cause actual results to differ from those expressed or implied in forward-looking statements are described under "Risk Factors" and in other sections of this prospectus. You should not place undue reliance on our forward-looking statements. Each forward-looking statement speaks only as of the date of the particular statement.

USE OF PROCEEDS

We estimate that we will receive net proceeds of approximately $ (based on an assumed offering price of $, the last reported sale price of our common stock on the Nasdaq National Market on   , 2004) from the sale of 3,420,000 shares of our common stock in this offering. "Net proceeds" is what we expect to receive after paying the underwriting discount and other expenses of the offering. We will not receive any proceeds from the sale of shares by the selling shareholders pursuant to this prospectus.

We intend to use the proceeds from this offering:

- to accelerate our drilling program on a selected basis as described under "Management's Discussion and Analysis of Financial Condition and Results of Operations--Liquidity and Capital Resources--Capital Expenditures";

- to retain larger working interests in some of our drilling prospects that we otherwise would have sold down or for which we would have sought partners; and

- for general corporate purposes.

Pending such use, we intend to use a portion of the net proceeds to repay the outstanding principal amount under our revolving credit facility. As of January 8, 2003, $7.0 million principal amount, bearing interest at a weighted average rate of 3.2%, was outstanding under our revolving credit facility with a borrowing base determined as of October 31, 2003 of $19.0 million. We originally borrowed this amount to fund our ongoing exploration program. See "Forward-Looking Statements" and "Management's Discussion and Analysis of Financial Condition and Results of Operations--Liquidity and Capital Resources--Financing Arrangements--Hibernia Credit Facility."

SELLING SHAREHOLDERS

The following table provides information regarding the beneficial ownership of our common stock held by the selling shareholders as of November 30, 2003.

	SHARES OF COMMON STOCK			
NAME	BENEFICIALLY OWNED PRIOR TO THE OFFERING(1)	OFFERED HEREBY	BENEFICIALLY OWNED AFTER THE OFFERING	AS A PERCENT TOTAL OUTSTAND
J.P. Morgan Partners (23A SBIC), L.P.(2)...........	5,143,909	1,145,883		
Mellon Ventures, L.P........	1,609,937	360,506		
Paul B. Loyd, Jr.	1,355,299	274,702		
Frank A. Wojtek.............	952,521	98,527		
Douglas A.P. Hamilton(3)....	851,472	250,379		
S.P. Johnson IV.............	841,083	75,000		
DAPHAM Partnership L.P......	395,960	--		
The Douglas Hayes Pollock Hamilton Trust............	43,000	20,000		
The Carrie Hamilton Trust...	47,824	20,000		
The Olivia Jean Hamilton Trust.....................	47,824	20,000		
Berea Investors:				
Paul J. Harder............	3,906	875		
Arthur F. DuC. Mussara....	1,953	437		
Victor Rice...............	19,531	4,373		
William Ross..............	3,907	875		
Anthony B. Martino........	6,024	1,349		
Richard E. Turner, Jr. ...	3,906	560		
NBLN Limited Partnership..	11,718	2,624		
Dr. Brad Cohen............	3,906	875		
Thomas H. O'Neill, Jr. ...	4,236	949		
Albert Stickney...........	1,694	379		
James Wadsworth...........	4,236	949		

Richard J. Riley..........	1,694	379
Kenneth W. Colwell........	1,694	379
Total................	11,218,586	2,280,000

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(1) The table includes shares of common stock that can be acquired through the exercise of options, warrants and convertible securities within 60 days of November 30, 2003. Included are 155,000, 70,000, 165,000, 20,000, 20,000 and 26,666 shares that can be acquired through the exercise of options for Mr. Johnson, Mr. Wojtek, Mr. Webster, Mr. Hamilton, Mr. Loyd and J.P. Morgan Partners (23A SBIC), L.P. ("JPMorgan"), respectively. Also included are 92,006, 92,006, 92,006, 2,208,151 and 276,019 shares that can be acquired through the exercise of the warrants issued in 1999 for Mr. Webster, Mr. Hamilton, Mr. Loyd, JPMorgan and Mellon Ventures, L.P. ("Mellon"), respectively. 84,210 and 168,422 shares that can be acquired through the exercise of the warrants issued in 2002 are included for Mr. Webster and Mellon, respectively, 400,930 and 801,860 shares that can be acquired upon the conversion of the Series B preferred stock are included for Mr. Webster and Mellon, respectively.

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(2) JPMorgan is a Delaware limited partnership. Its general partner is J.P. Morgan Partners (23A SBIC Manager), Inc. ("JPMP (23A SBIC Manager)"), a wholly owned subsidiary of JP Morgan Chase Bank ("JPM Chase Bank"), a wholly owned subsidiary of JP Morgan Chase & Co., a publicly traded company ("JPM Chase"). Each of JPMP (23A SBIC Manager), JPM Chase Bank and JPM Chase may also be considered the beneficial owner of these shares; however, each disclaims beneficial ownership except to the extent of its pecuniary interest in the shares. Shares shown include 15,833, 4,166 and 7,500 shares of common stock that can be acquired through the exercise of options within 60 days of November 30, 2003 by Mr. Behrens, Mr. Martin and Arnold Chavkin, our former director. Mr. Behrens, Mr. Martin and Mr. Chavkin are obligated to transfer any shares issued in connection with the exercise of the options to JPMorgan.

(3) Shares shown do not include (i) 395,960 shares of common stock beneficially owned by DAPHAM Partnership, L.P., the limited partner of which is a charitable remainder trust of which Mr. Hamilton, his wife and children are among the beneficiaries and (ii) 138,648 shares of common stock beneficially owned by the trusts identified in the table established for the benefit of Mr. Hamilton's children, and for each of which Mr. Hamilton's wife serves as trustee. Mr. Hamilton disclaims beneficial ownership of all of such shares.

Some of the selling shareholders either have or have had a material relationship with us within the past three years. Messrs. Hamilton, Loyd, Webster, Wojtek and Johnson have each been a member of our Board of Directors since 1993. Mr. Webster has been the Chairman of our Board of Directors since June 1997. Mr.

Wojtek served as our Chief Financial Officer, Vice President, Secretary and Treasurer from 1993 until August 2003. Mr. Johnson has served as our President and Chief Executive Officer since December 1993. See "Management" for more information about these relationships.

In February 2002, we sold 60,000 shares of our Series B preferred stock and warrants to purchase 252,632 shares of our common stock for an aggregate purchase price of $6.0 million. We sold $4.0 million of Series B preferred stock and 168,422 warrants to Mellon and $2.0 million of Series B preferred stock and 84,210 warrants to Mr. Webster, the Chairman of our Board of Directors. For information on this transaction, please read "Management's Discussion and Analysis of Financial Condition and Results of Operations--Liquidity and Capital Resources--Financing Arrangements--Series B Preferred Stock."

In connection with our 2002 sales of the Series B preferred stock and related warrants, we and the investors entered into a shareholders' agreement providing that if the holders of at least 51% of our common stock then outstanding approve a merger, sale of our company or sale of all or substantially of our assets, each such investor will vote in favor of the proposed transaction, subject to certain conditions. Under the 2002 shareholders' agreement, we granted Mellon and Mr. Webster specified preemptive rights to purchase certain securities issuable by us.

In December 1999, we sold $22.0 million principal amount of 9% Senior Subordinated Notes due 2007, 3,636,364 shares of our common stock at a price of $2.20 per share and warrants expiring in 2007 to purchase up to 2,760,189 shares of our common stock at an exercise price of $2.20 per share to CB Capital Investors, L.P. (now JPMorgan), Mellon and Messrs. Loyd, Hamilton and Webster. For information on this transaction, please read "Management's Discussion and Analysis of Financial Condition and Results of Operations--Liquidity and Capital Resources--Financing Arrangements--Senior Subordinated Notes and Related Securities."

In connection with this 1999 transaction, we entered into a shareholders' agreement with the investors and Mr. Johnson, Mr. Wojtek and DAPHAM Partnership, L.P. (collectively, the "1999 Shareholders") which provides that so long as to JPMorgan owns (a) at least 15% of our common stock (with percentage ownerships being determined as specified in the agreement), the 1999 Shareholders agree to vote their shares to cause the number of directors constituting our Board of Directors to be seven and to cause the election of two directors to be nominated by JPMorgan and (b) at least 7.5% of our common stock, the 1999 Shareholders agree to vote their shares to cause the number of directors constituting our Board of Directors to be seven and to cause the election of one director to be nominated by JPMorgan. The 1999 Shareholders also have agreed that, if at any time after December 15, 2004, JPMorgan then owns at least 15% of our common stock, unless there shall have occurred certain completed or proposed sale transactions involving us or we have a minimum public float of common stock of not less than $40 million and a minimum average weekly trading volume of 250,000 shares, JPMorgan has the right to designate two additional members to our Board of Directors, and the size of our Board of Directors shall be

increased accordingly. The 1999 Shareholders have agreed to vote their shares in accordance with this arrangement. We were entitled to increase the size of the Board by one additional member in fiscal 2000. If we at any other time increase the size of the Board of Directors, the 1999 Shareholders have agreed to take action, including the voting of their securities, to cause to be elected the number of directors nominated by JPMorgan necessary to maintain the applicable proportion of directors nominated by JPMorgan to the Board of Directors.

The 1999 shareholders' agreement gave JPMorgan and affiliates certain preemptive rights similar to those in the 2002 shareholders' agreement.

In November 1999 we entered into a month-to-month agreement with San Felipe Resources Company, an entity owned by Mr. Webster, under which he provides consulting services to us in exchange for a fee of $9,000 per month, which was increased to $12,000 per month effective April 2003. In December 2001 and April 2003, we granted options to purchase 75,000 and 80,000 shares of our common stock under our incentive plan to Mr. Webster at the price of $4.01 and $4.43 per share, respectively, the fair market value of the date of each grant, for consulting services.

In December 2001 we sold to Mr. Webster a 2% working interest in certain leases in Matagorda County and the right to participate in the Staubach #1 well located within those leases in exchange for $20,000 and the payment by Mr. Webster of a 33% promoted interest for the drilling costs through casing point of that well. The terms of this sale were consistent with the terms of sales of other participants in this project.

During the years ended December 31, 2001 and 2002 and during 2003, we participated in the drilling of two wells, one well and no wells, respectively, that were operated by a subsidiary of Brigham Exploration Company ("Brigham"). During the year ended December 31, 2002 and during 2003, Brigham participated in the drilling of two wells and two wells, respectively, operated by us. Mr. Webster is a member of the board of directors of Brigham. Mr. Webster is also a managing director of a merchant banking affiliate of the beneficial owner of approximately 35% of the common stock of the parent company of Brigham Oil and Gas, L.P.

Berea Associates, LLC, Berea Oil & Gas Corp., PAC Finance (USA) Inc., William R. Ziegler, Thomas O'Neill, Jr. and Berea Associates II LLC were participants with us in a 2001 exploration program. We granted these individuals and entities an exchange option whereby each participant was entitled to elect to exchange its interest in the program for our common stock. In October 2003, we issued to these participants who exercised their election approximately 168,000 shares of our common stock in exchange for their interests in that program. The individuals listed below Berea Investors in the table above are transferees of the interests of Berea Associates, LLC and Berea Associates II LLC in the exchange program.

In June 2003, we formed Pinnacle Gas Resources, Inc., a corporate joint venture with an unrelated entity and CSFB Private Equity, which is an affiliate of Mr. Webster. That transaction is described in "Business and Properties--Pinnacle Transaction."

In the third quarter of 2003, we paid Mr. Wojtek $251,486 in severance payments in accordance with his employment agreement.

CAPITALIZATION

The table below shows our capitalization:

- on September 30, 2003; and

- on September 30, 2003 on an as-adjusted basis to give effect to this offering at a public offering price of $ per share, the last reported sales price on , 2004, and the temporary application of the proceeds as set forth in "Use of Proceeds."

You should read this table in conjunction with our consolidated financial statements and related notes that are included in this prospectus.

	SEPTEMBER 30, 2003	
	ACTUAL	AS ADJUSTED
	(in thousands)	
CASH	$ 4,426	
LONG-TERM DEBT:		
Revolving credit facility	$ 7,000	
Senior subordinated notes, related parties	26,605	
Capital lease obligations	161	
Nonrecourse note	388	
Total long-term debt	34,154	
PREFERRED STOCK (10,000,000 SHARES AUTHORIZED):		
Series B convertible participating preferred stock (150,000 shares are designated as convertible participating shares, with 68,559 convertible participating shares issued and outstanding)	6,925	
SHAREHOLDERS' EQUITY:		
Warrants (3,262,821 outstanding)	780	
Common stock, par value $0.01 (40,000,000 shares authorized with 14,385,551 issued and outstanding)	144	
Additional paid in capital	63,821	
Retained earnings	9,391	
Accumulated other comprehensive loss	(67)	
Total shareholders' equity	74,069	
Total capitalization	$115,148	

PRICE RANGE OF COMMON STOCK AND DIVIDEND POLICY

Our common stock, par value $0.01 per share, commenced trading on the Nasdaq National Market on August 6, 1997 under the symbol CRZO. The following table sets forth the high and low bid prices per share of our common stock on the Nasdaq National Market for the periods indicated. The sales information below reflects interdealer prices, without retail mark-ups, mark-downs or commissions and may not necessarily represent actual transactions.

	HIGH	LOW
2002:		
First Quarter	$6.000	$4.100
Second Quarter	5.750	4.260
Third Quarter	4.700	3.600
Fourth Quarter	5.730	3.900
2003:		
First Quarter	5.900	4.500
Second Quarter	6.880	4.250
Third Quarter	7.440	5.000
Fourth Quarter	7.940	6.300
2004:		
First Quarter (through January 12, 2004)	7.550	7.380

The closing market price of our common stock on January 12, 2004 was $7.55 per share. As of January 12, 2004, there were an estimated 66 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 agreement with Hibernia National Bank and the terms of our senior subordinated notes restrict our ability to pay dividends. See "Management's Discussion and Analysis of Financial Condition and Results of Operations--Liquidity and Capital Resources."

SELECTED CONSOLIDATED FINANCIAL DATA

This section presents our selected historical financial data. This data should be read in conjunction with the consolidated financial statements, related notes and other financial information included and incorporated by reference herein, as well as "Management's Discussion and Analysis of Financial Condition and Results of Operations." The selected financial data in this section is not intended to replace the consolidated financial statements.

We derived the statement of operations data and statement of cash flows data for the years ended December 31, 2000, 2001 and 2002, and balance sheet data as of December 31, 2001 and 2002 from the audited consolidated financial statements included in this prospectus. We derived the statement of operations data and statement of cash flows data for the years ended December 31, 1998 and 1999 and the balance sheet data as of December 31, 1998, 1999 and 2000 from audited consolidated financial statements that are not included in this prospectus. We derived the statement of operations data and statement of cash flows data for the nine months ended September 30, 2002 and 2003 and balance sheet data as of September 30, 2002 and 2003 from the unaudited consolidated financial statements included in this prospectus. The unaudited consolidated financial statements include all adjustments, consisting of normal recurring accruals, which we consider necessary for a fair presentation of our financial position and results of operations for these periods. The financial statements as of and for the year ended December 31, 2002 were audited by Ernst & Young LLP, independent auditors. The financial statements as of and for the years ended December 31, 1998, 1999, 2000 and 2001 were audited by Arthur Andersen LLP. In 2002, we dismissed Arthur Andersen LLP as our independent public accountants and retained Ernst & Young LLP to act as our independent auditors.

	YEAR ENDED DECEMBER 31,				
	1998	1999	2000	2001	2002
			(in thousands, except per share dat		
STATEMENT OF OPERATIONS DATA:					
Oil and natural gas revenues...........	$ 7,859	$ 10,204	$ 26,834	$ 26,226	$ 26,802
Cost and expenses:					
Oil and natural gas operating expenses..........................	2,770	3,036	4,941	4,138	4,908
Depreciation, depletion and amortization......................	3,952	4,301	7,170	6,492	10,574
General and administrative...........	2,667	2,195	3,143	3,333	4,133
Writedown of oil and gas properties........................	20,305	--	--	--	--
Stock option compensation............	-	-	652	(558)	(84
Total costs and expenses...........	29,694	9,532	15,906	13,405	19,531
Operating income (loss)................	(21,835)	672	10,928	12,821	7,271
Equity loss of Pinnacle Gas Resources, Inc................................	-	-	-	-	-
Interest income (net of amounts capitalized and interest expense)....	285	13	579	269	54
Other income, net.....................	-	-	1,482	1,777	274
Income (loss) before income taxes......	(21,550)	685	12,989	14,867	7,599
Income tax expense (benefit)...........	(2,218)	(1,057)	1,004	5,336	2,809
Net income (loss) before cumulative effect of change in accounting principle...........................	(19,332)	1,742	11,985	9,531	4,790
Dividends and accretion on Preferred Stock..............................	-	-	-	-	588
Cumulative effect of change in accounting principle................	-	(78)	-	-	-
Net income (loss) available to common shareholders(1).....................	$(19,332)	$ 1,664	$ 11,985	$ 9,531	$ 4,202
Basic earnings (loss) per common share(1)............................	$ (2.15)	$ 2.00	$ 0.85	$ 0.68	$ 0.30
Diluted earnings (loss) per common share(1)............................	(2.15)	2.00	0.74	0.57	0.26

	YEAR ENDED DECEMBER 31,				
	1998	1999	2000	2001	2002
	(in thousands, except per share dat				
Weighted average shares outstanding:					
Basic	10,375	10,544	14,028	14,059	14,158
Diluted	10,375	10,546	16,256	16,731	16,148

	YEAR ENDED DECEMBER 31,				
	1998	1999	2000	2001	2002
	(in thousands)				
STATEMENT OF CASH FLOWS DATA:					
Net cash provided by operating activities	$ 2,387	$ 2,200	$ 17,133	$ 23,951	$ 19,925
Net cash used in investing activities	(36,790)	(13,500)	(16,438)	(31,224)	(24,100
Net cash provided by (used in) financing activities	32,916	21,457	(3,823)	2,292	5,682

	AS OF DECEMBER 31,				
	1998	1999	2000	2001	2002
	(in thousands)				
BALANCE SHEET DATA:					
Working capital	$ 4,483	$ 8,338	$ 6,433	$ (582)	$ (1,442
Property and equipment, net	57,878	64,337	72,129	104,132	120,526
Total assets	64,988	83,666	93,000	117,392	135,388
Long-term debt, including current maturities	12,056	37,170	34,556	38,188	42,012
Mandatorily redeemable preferred stock	30,731	-	-	-	-
Convertible participating preferred stock	-	-	-	-	6,373
Shareholders' equity	11,202	40,853	52,939	63,204	66,816

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(1) Net income for the year ended December 31, 1999 excludes, and earnings per share for the year ended December 31, 1999 includes, the discount on the redemption of our preferred stock in the amount of $21.9 million.

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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 prospectus. Unless explicitly stated otherwise, or the context otherwise requires, all references in this section to planned capital expenditures or planned drilling activities assume the completion of this offering.

GENERAL OVERVIEW

For the year ended December 31, 2002 and for the first nine months of 2003, we achieved record drilling success rates, levels of production, natural gas and oil revenues and net income available to shareholders for any twelve- and nine-month period, respectively, in our history.

In 2002, we produced a record 7.2 Bcfe compared to 5.4 Bcfe in 2001. In the first nine months of 2003, we produced 5.6 Bcfe, a record for any nine-month period and an improvement over production of 5.1 Bcfe in the first nine months of 2002. These increasing production levels in 2003 are due to our drilling success.

In 2002, we drilled 20 wells (7.1 net) in the onshore Gulf Coast with a success rate of 85% compared to a success rate of 80% in 2001, in which we drilled 25 wells (7.6 net). During the first nine months of 2003, we drilled 22 wells (8.2 net) with a success rate of 86%. Between January 1, 2001 and September 30, 2003, 93% of our wells drilled were exploratory and 7% were development. In 2003, we drilled 38 wells, with 36 wells in the onshore Gulf Coast area.

In 2002, both our revenues and our net income increased: our natural gas and oil revenues reached a record level at $26.8 million, and our net income available to common shareholders was $4.2 million, or $0.30 and $0.26 per basic and fully diluted share, respectively. In 2001, our natural gas and oil revenues were $26.2 million and our net income available to common shareholders was $9.5 million, or $0.68 and $0.57 per basic and fully diluted share, respectively. In the first nine months of 2003, our natural gas and oil revenues reached a nine-month record level of $29.6 million, as compared to $17.6 million during the first nine months of 2002. Our net income available to common shareholders was $6.3 million in the 2003 nine-month period, or $0.45 and $0.38 per basic and fully diluted share, respectively, as compared to $2.0 million, or $0.14 and $0.12 per basic and fully diluted share, respectively, for the first nine months of 2002. These increases in natural gas and oil revenues and net income were attributable partly to the high levels of production discussed above and to high commodity prices.

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. Including the effects of hedging activities, our realized natural gas price was 31% lower and our realized oil price was 3% higher in 2002 than in 2001, and our realized natural gas price was 72% higher and our realized oil price was 25% higher during the first nine months of 2003 than in the comparable period in 2002.

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 hedging 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 2004, we expect capital expenditures to be approximately $40 to $45 million, as compared to $25.3 million in 2003. In the first nine months of 2003, we incurred $20.4 million in capital and exploration expenditures, as compared to $20.9 million in the first nine months of 2002.

At September 30, 2003, our debt-to-total capitalization ratio was 31.0%, an improvement from 36.5% at the end of 2002. This improvement was primarily the result of the increased shareholders' equity from net income, a decrease in the outstanding debt on the Hibernia credit facility and a reduction in our nonrecourse note to Rocky Mountain Gas, Inc., both as described under "--Liquidity and Capital Resources--Financing Arrangements."

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 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. We account for our interest in Pinnacle using the equity method. As a result, our contributed operations and reserves are no longer directly reflected in our financial statements. We retained our interests in approximately 189,000 gross acres in the Castle Rock 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.

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.

RECENT DEVELOPMENTS

Fourth Quarter 2003 Operating Results

During the fourth quarter of 2003, in our core areas in the onshore Gulf Coast of Texas and Louisiana, we participated in the drilling of 11 gross exploratory wells, ten of which were successful. Also during the quarter, in our Barnett Shale Project we participated in the drilling of two gross (one net) exploratory wells and two gross (one net) development wells, all of which were successful. On a combined basis for these two areas, we had a 93.3% success rate for the quarter.

Production during the fourth quarter of 2003 was estimated at 1.85 Bcfe, bringing our 2003 annual production to an estimated record level of 7.5 Bcfe, an increase of 3.5% over our 2002 production level. Approximately 72% of our production during the fourth quarter of 2003 and 64% of our production in the full year 2003 was natural gas. We estimate that fourth quarter 2003 sales prices, including the effect of hedging activities, averaged approximately $4.78 per Mcf and $29.61 per barrel. Based on our preliminary reserve estimates, we believe that in 2003 we more than replaced our production with proved reserve additions from our drilling activities.

Potential Barnett Shale Acquisition

We have entered into negotiations with a private company to purchase working interests and acreage in certain oil and gas wells located in Denton County, Texas in the Newark East Field in the Barnett Shale trend. This potential acquisition, with an expected purchase price of $7.2 million, includes non-operated working interests ranging from 12.5% to 45% over 3,800 acres. As of January 1, 2004, the 14 producing wells (5.0 net) that would be included in the acquisition were producing a net 1.4 MMcf/d with another five wells (1.3 net) waiting for pipeline hook-up. We expect the undeveloped acreage to contribute additional drilling locations, 13 of which will target proved undeveloped reserves and 18 of which will be exploratory.

We expect that we would finance the acquisition with our current revolving credit facility or, alternatively, with a new project financing facility that we would seek to obtain. We currently have targeted a closing date of February 16, 2004 for the acquisition. There can be no assurance that the transaction described above will be completed on the terms or timing described above or at all. Regardless of whether this transaction is completed, we intend to continue to pursue growth opportunities in this geologic trend.

RESULTS OF OPERATIONS

The following table summarizes production volumes, average sales prices and operating revenues for our natural gas and oil operations for the years ended December 31, 2000, 2001 and 2002 and for the nine months ended September 30, 2002 and 2003:

	YEAR ENDED DECEMBER 31, 2000	YEAR ENDED DECEMBER 31, 2001	% INCREASE (DECREASE) FROM 2000 TO 2001	YEAR ENDED DECEMBER 31, 2002	% INCREA (DECREAS FROM 200 TO 2002
PRODUCTION VOLUMES					
Oil and condensate (MBbls)...............	198	160	(20)%	401	151%
Natural gas (MMcf)......	5,460	4,432	(19)	4,801	8
Natural gas equivalent					

(MMcfe)............	6,651	5,390	(19)	7,207	34
AVERAGE SALES PRICES(1)					
Oil and condensate (MBbls)...............	$ 27.81	$ 24.28	(13)%	$ 24.94	3%
Natural gas (MMcf)......	3.90	5.04	(29)	3.50	(31)
OPERATING REVENUES (IN THOUSANDS)..............	$26,834	$26,226	(2)%	$26,802	2%

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(1) Includes impact of hedging activities.

Nine Months Ended September 30, 2003 Compared to the Nine Months Ended September 30, 2002

Natural gas and oil revenues for the nine months ended September 30, 2003 increased 69% to $29.6 million from $17.6 million for the same period in 2002. Production volumes for natural gas during the nine months ended September 30, 2003 decreased 3% to 3.4 Bcf from 3.5 Bcf for the same period in 2002. Average natural gas prices increased 72% to $5.56 per Mcf in the first nine months of 2003 from $3.24 per Mcf in the same period in 2002. Production volumes for oil in the nine months ended September 30, 2003 increased 39% to 363 MBbls from 261 MBbls for the same period in 2002. Average oil prices increased 25% to $29.08 per barrel in the first nine months of 2003 from $23.34 per barrel in the same period in 2002. The increase in oil production was due primarily to the commencement of production at six wells offset by the natural decline in production from other wells. The decrease in natural gas production was primarily due to a workover at one well and natural production declines in other wells offset by the commencement of production at new wells. Natural gas and oil revenues include the impact of hedging activities as discussed below under "Management's Discussion and Analysis of Financial Condition and Results of Operations--Critical Accounting Policies and Estimates--Derivative Instruments and Hedging Activities."

Natural gas and oil operating expenses for the nine months ended September 30, 2003 increased 38% to $5.1 million from $3.7 million for the same period in 2002 primarily due to higher severance taxes and other operating costs associated with the addition of new production. Operating expenses per equivalent unit increased 25% to $0.90 per Mcfe in the first nine months of 2003 from $0.72 per Mcfe in the same period in 2002 primarily as a result of the natural decline in production on older wells and the addition of a relatively higher cost new well.

General and administrative (G&A) expense for the nine months ended September 30, 2003 increased 43% to $4.3 million from $3.0 million for the same period in 2002. The increase in G&A expense was due primarily to employee severance costs and the addition of contract staff to handle increased drilling and production activities, higher compensation costs and higher insurance.

Depreciation, depletion and amortization (DD&A) expense for the nine months ended September 30, 2003 increased 19% to $8.7 million from $7.3 million for the same period in 2002. This increase was due to increased production and additional seismic and drilling costs.

Interest income for the nine months ended September 30, 2003 increased to $50,000 from $44,000 in the first nine months of 2002 primarily as a result of higher cash balances during the first quarter of 2003. Capitalized interest was $2.2 million in the first nine months of 2003 and 2002.

Provision for income taxes increased to $4.1 million for the nine months ended September 30, 2003 from $1.5 million for the same period in 2002 as a result of higher taxable income based on the factors described above.

We adopted Financial Accounting Standards Board (FASB) Statement of Financial Accounting Standards (SFAS) No. 143, "Accounting for Asset Retirement Obligations," effective January 1, 2003 and recorded a cumulative effect of change in accounting principle of $0.1 million in the nine months ended September 30, 2003.

Income before income taxes for the nine months ended September 30, 2003 increased to $11.1 million from $3.9 million in the same period in 2002. Net income for the nine months ended September 30, 2003 increased to $6.3 million from $2.0 million for the same period in 2002 primarily as a result of the factors described above.

Year Ended December 31, 2002 Compared to the Year Ended December 31, 2001

Our natural gas and oil revenues for 2002 increased 2% to $26.8 million from $26.2 million in 2001. Production volumes for natural gas in 2002 increased 8% to 4,801 MMcf from 4,432 MMcf in 2001, due primarily to the commencement of production at five wells, offset by natural production declines in other wells, primarily from the initial Matagorda County Project wells. Realized average natural gas prices decreased 31% to $3.50 per Mcf in 2002 from $5.04 per Mcf in 2001.

Production volumes for oil in 2002 increased 151% to 401 MBbls from 160 MBbls in 2001, due primarily to the commencement of production at four wells, offset by natural production declines in other older wells. Natural gas and oil revenues include the impact of hedging activities as discussed below under "--Critical Accounting Policies and Estimates--Derivative Instruments and Hedging Activities." Average oil prices increased 3% to $24.94 per Bbl in 2002 from $24.28 per Bbl in 2001.

Natural gas and oil operating expenses for 2002 increased 19% to $4.9 million from $4.1 million in 2001, primarily as a result of the addition of new natural gas and oil wells drilled and completed since December 31, 2001 and higher ad valorem taxes. Operating expenses per equivalent unit in 2002 decreased to $0.68 per Mcfe from $0.77 per Mcfe in 2001. The per-unit cost decreased primarily as a result of the addition of higher-production-rate, lower-cost-per-unit wells, offset by an increase in ad valorem taxes and decreased production of natural gas as wells naturally declined.

DD&A expense for 2002 increased 63% to $10.6 million from $6.5 million in 2001. This increase was due primarily to increased production and the additional seismic and drilling costs added to the proved property cost base.

G&A expense for 2002 increased 24% to $4.1 million from $3.3 million for 2001. The increase in G&A expense was due primarily to the addition of contract staff to handle increased drilling and production activities and higher insurance costs.

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Interest income for 2002 decreased to $0.1 million from $0.3 million in 2001 primarily as a result of lower interest rates during 2002. Capitalized interest decreased to $3.1 million in 2002 from $3.2 million in 2001 primarily due to lower interest costs during 2002.

Provision for income taxes decreased to $2.8 million in 2002 from $5.3 million in 2001.

Dividends and accretion of discount on preferred stock increased to $0.6 million in 2002 from none in 2001 as a result of our sale of preferred stock in the first quarter of 2002.

Net income for 2002 decreased to $4.8 million from $9.5 million in 2001 primarily as a result of the factors described above.

Year Ended December 31, 2001 Compared to the Year Ended December 31, 2000

Natural gas and oil revenues for 2001 decreased 2% to $26.2 million from $26.8 million in 2000. Production volumes for natural gas in 2001 decreased 19% to 4,432 MMcf from 5,461 MMcf in 2000, due primarily to the sale of a project during 2000 and the natural decline in production at certain wells, offset by the commencement of production at other wells. Realized average natural gas prices increased 29% to $5.04 per Mcf in 2001 from $3.90 per Mcf in 2000.

Production volumes for oil in 2001 decreased 20% to 160 MBbls from 199 MBbls in 2000 due to the natural decline in production at certain wells, offset by the commencement of production of another well. Natural gas and oil revenues include the cash effect of hedging activities as discussed below under "Critical Accounting Policies and Estimates--Derivative Instruments and Hedging Activities." Average oil prices decreased 13% to $24.28 per Bbl in 2001 from $27.81 per Bbl in 2000.

Natural gas and oil operating expenses for 2001 decreased 16% to $4.1 million from $4.9 million in 2000, primarily as a result of the lower production taxes and the implementation of cost reduction measures in fields with decreased production. Operating expenses per equivalent unit in 2001 increased to $0.77 per Mcfe from $0.74 per Mcfe in 2000. The per-unit cost increased primarily as a result of an increase in severance taxes and decreased production of natural gas as wells naturally declined.

Depreciation, depletion and amortization expense for 2001 decreased 9% to $6.5 million from $7.2 million in 2000. This decrease was primarily due to the seismic and drilling costs added to the proved property cost base.

G&A expense for 2001 increased 6% to $3.3 million from $3.1 million for 2000. The increase in G&A expense was due primarily to the addition of staff to handle increased drilling and production activities and also to stock option compensation expense, a noncash charge resulting from a decrease during 2001 and an increase during the last six months of 2000 in the stock price underlying the stock options that we repriced in February 2000.

Interest expense, net of amounts capitalized, for 2001 decreased 47% to $6,873 from $13,003 in 2000.

Provision for income taxes increased to $5.3 million in 2001 from $1.0 million in 2000 as a result of an adjusted noncash valuation allowance during 2000 on net operating loss carryforwards expected to be realized that resulted in a deferred income tax benefit adjustment of $3.6 million, which reduced our effective tax rate to 8% in 2000.

Other income for the year ended December 31, 2001 included a gain on the sale of an investment in Michael Petroleum Corporation of $3.9 million, offset by:

- a charge and related legal expenses of $1.4 million in respect of the final settlement of litigation with BNP Petroleum Corporation; and

- a noncash valuation allowance of $0.8 million relating to certain hedge arrangements with Enron North America Corp.

Net income for 2001 decreased to $9.5 million from $12.0 million in 2000 as a result of the factors described above.

LIQUIDITY AND CAPITAL RESOURCES

We have made and expect to make capital expenditures in excess of our net cash flows provided by operating activities. We will require additional sources of financing to fund drilling expenditures on properties we currently own and to fund leasehold costs and geological and geophysical costs on our exploration projects.

While we believe that current cash balances and anticipated cash provided by operating activities for 2004 will provide sufficient capital to carry out our exploration plans for that time period, our management continues to seek financing for our capital program from a variety of sources. We may not be able to obtain additional financing on terms that would be acceptable to us. If we cannot obtain acceptable financing, we anticipate that we may be required to limit or defer our planned natural gas and oil exploration and development program, thereby adversely affecting the recoverability and ultimate value of our natural gas and oil properties. See "Risk Factors--We have substantial capital requirements that, if not met, may hinder operations."

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, and borrowings, primarily under revolving credit facilities and through the issuance of senior subordinated notes.

Cash flows provided by operating activities were $17.1 million, $24.0 million and $19.9 million for 2000, 2001 and 2002, respectively, and $12.3 million and $23.5 million for the nine months ended September 30, 2002 and 2003, respectively. The increase in cash flows provided by operating activities in 2003 as compared to 2002 was due primarily to additional revenue resulting from higher natural gas and oil prices and higher oil and condensate production, offset by an increase in our working capital during the first nine months of 2003.

Estimated maturities of long-term debt are $3.9 million in 2004, $8.5 million in 2005 and the remainder in 2007.

Capital Expenditures

We have budgeted capital expenditures in 2003 of approximately $25.9 million, of which we expect to use $5.2 million to fund 3-D seismic surveys and acquire land and $20.7 million for drilling activities in our project areas. We have budgeted to drill approximately 25 wells (9.9 net) in the onshore Gulf Coast region and no coalbed methane wells in 2003. In 2004, we expect capital expenditures to be approximately $40 to $45 million (a 58 to 78% increase over our expected 2003 capital expenditures). We expect to drill 38 wells in 2004 (18.5 net), 30 of which we expect to operate. The actual number of wells drilled and the amount of capital expended depends on available financing, cash flow, availability and cost of drilling rigs, land and partner issues and other factors.

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. Capital expenditures were $20.4 million for the nine months ended September 30, 2003, which included $2.2 million of capitalized interest and general and administrative costs. Our drilling efforts in the onshore Gulf Coast region resulted in the successful completion of 17 wells (6.0 net) in 2002 and 19 wells (5.2 net) in the nine months ended September 30, 2003. Of the 77 coalbed methane wells (19 net) we drilled or acquired in the Rocky Mountain region through September 30, 2003, 24 wells (8 net) are currently producing and 53 wells (21 net) are in various stages of evaluation.

Pursuant to an exchange election provided in a letter agreement dated May 1, 2001, with some of the participants in the Carrizo 2001 Seismic and Acreage Program, we issued to those participants who exercised their election approximately 168,000 shares of our common stock in exchange for the participants' interest in that program, including interests in approximately 350 square miles of 3-D seismic data and working interests in specified producing properties. The exchange transaction was effective on October 10, 2003 and was valued at approximately $1.2 million using the closing price of our stock on that date.

Financing Arrangements

Hibernia Credit Facility

On May 24, 2002, we entered into a credit agreement with Hibernia National Bank that matures on January 31, 2005, and repaid our prior facility with Compass Bank. The Hibernia credit facility provides a revolving line of credit of up to $30.0 million. It is secured by substantially all of our producing assets.

The borrowing base will be determined by Hibernia National Bank at least semi-annually on each October 31 and April 30. The borrowing base as of October 31, 2003 was $19.0 million, of which $7.0 million was drawn as of that date. Each party to the credit agreement can request one unscheduled borrowing base determination subsequent to each scheduled determination. The borrowing base will at all times equal the borrowing base most recently determined by Hibernia National Bank, less quarterly borrowing base reductions required subsequent to such determination. The quarterly borrowing base reduction effective January 31, 2004 will be $3.0 million.

If the outstanding principal balance of the Hibernia 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 Hibernia National Bank's 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 interest rate applicable to incremental borrowings under this credit facility will be, at our option, a eurodollar rate or a base rate, in each case plus an applicable margin based upon borrowing levels.

We are subject to specified covenants under the terms of the Hibernia credit facility, including but not limited to maintaining a minimum current ratio, a minimum quarterly debt services coverage ratio and a minimum level of shareholders' equity. The Hibernia credit facility also places restrictions on additional indebtedness, dividends to shareholders, liens, investments, mergers, acquisitions, asset dispositions, asset pledges and mortgages, change of control, repurchase or redemption for cash of our common or preferred stock, speculative commodity transactions and other matters.

Rocky Mountain Gas Note

In June 2001, our subsidiary CCBM issued a nonrecourse promissory note in the amount of $7.5 million to Rocky Mountain Gas, Inc. (RMG) as consideration for specified interests in natural gas and oil leases held by RMG in Wyoming and Montana. At September 30, 2003, the outstanding principal balance of this note was $1.0 million.

Capital Leases

We have entered into capital lease agreements, each secured by specified production equipment, with payment obligations of $0.4 million in 2004, $0.3 million in 2005 and $0.1 million in 2006.

Senior Subordinated Notes and Related Securities

In December 1999, we sold $22.0 million principal amount of 9% Senior Subordinated Notes due 2007. The senior subordinated notes were sold at a discount of $0.7 million, which is being amortized over the life of the notes. Interest is payable quarterly beginning March 31, 2000. We may elect, until December 2004, to increase the amount of the senior subordinated notes for up to 60% of the interest rate which would otherwise be payable in cash. As of December 31, 2002 and September 30, 2003, the outstanding balance of the senior subordinated notes had been increased by $3.9 million and $5.0 million, respectively, for such interest paid in kind.

Concurrently with the sale of the senior subordinated notes, we sold 3,636,364 shares of our common stock at a price of $2.20 per share and warrants expiring in December 2007 to purchase up to 2,760,189 shares

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of our common stock at an exercise price of $2.20 per share. For accounting purposes, the warrants were valued at $0.25 each. We sold the warrants to CB Capital Investors, L.P. (now JPMorgan), Mellon, Paul B. Loyd, Jr., Steven A. Webster and Douglas A.P. Hamilton.

We are subject to specified covenants under the terms of the securities purchase agreement related to the senior subordinated notes, including but not limited to maintenance of a specified tangible net worth and a debt service coverage ratio and limits on our ability to incur indebtedness and to engage in certain transactions and activities.

Series B Preferred Stock

In February 2002, we sold 60,000 shares of our Series B preferred stock and warrants to purchase 252,632 shares of our common stock for an aggregate purchase price of $6.0 million. We sold $4.0 million of Series B preferred stock and 168,422 warrants to Mellon and $2.0 million of Series B preferred stock and 84,210 warrants to Steven A. Webster, our Chairman of the Board. The investors may convert the Series B preferred stock into common stock at a conversion price of $5.70 per share, subject to adjustment for transactions including issuance of common stock or securities convertible into or exercisable for common stock at less than the conversion price of the Series B preferred stock. The approximate $5.8 million net proceeds of this financing were used to fund our ongoing exploration and development program and for general corporate purposes.

Dividends on the Series B preferred stock are payable either in cash at a rate of 8% per annum or, at our option, by payment in kind of additional shares of the Series B preferred stock at a rate of 10% per annum. At December 31, 2002 and September 30, 2003, the outstanding balance of the Series B preferred stock had been increased by $0.5 million (5,294 shares) and $0.9 million (8,559 shares), respectively, for dividends paid in kind. At September 30, 2003, we had accrued a dividend of $0.2 million that we paid on December 31, 2003. In addition to the foregoing, if we declare a cash dividend on our common stock, the holders of shares of Series B preferred stock are entitled to receive for each share of Series B preferred stock a cash dividend in the amount of the cash dividend that would be received by a holder of the common stock into which that share of Series B preferred stock is convertible on the record date for the cash dividend. Unless all accrued dividends on the Series B preferred stock shall have been paid and a sum sufficient for the payment thereof set apart, no distributions may be paid on any Junior Stock (as defined in the Statement of Resolutions for the Series B preferred stock) (which includes the common stock), and no redemption of any junior stock shall occur other than subject to specified exceptions.

We must redeem the Series B preferred stock at any time after the third anniversary of its initial issuance upon request from any holder at a price per share equal to Purchase Price/Dividend Preference (as defined below). We may redeem the Series B preferred stock after the third anniversary of its issuance at a price per share equal to the Purchase Price/Dividend Preference and, prior to that time, at varying preferences to the Purchase Price/Dividend Preference. "Purchase Price/Dividend Preference" is defined to mean, generally, $100 plus all cumulative and accrued dividends.

In the event of any dissolution, liquidation or winding up or specified mergers or sales or other disposition by us of all or substantially all of our assets, the holder of each share of Series B preferred stock then outstanding will be entitled to be paid per share of Series B preferred stock, prior to the payment to holders of our common stock and out of our assets available for distribution to our shareholders, the greater of:

- $100 in cash plus all cumulative and accrued dividends; and

- in specified circumstances, the "as-converted" liquidation distribution, if any, payable in such liquidation with respect to each share of common stock.

Upon the occurrence of specified events constituting a "Change of Control" (as defined in the Statement of Resolutions), we must make an offer to each holder of Series B preferred stock to repurchase all of that holder's Series B preferred stock at an offer price per share of Series B preferred stock in cash equal to

105% of the Change of Control Purchase Price, which is generally defined to mean $100 plus all cumulative and accrued dividends.

The warrants issued in connection with the Series B preferred stock have a five-year term, entitle the holders to purchase up to 252,632 shares of our common stock at a price of $5.94 per share, subject to adjustment, and are exercisable at any time after issuance. For accounting purposes, the warrants are valued at $0.06 per warrant.

EFFECTS OF INFLATION AND CHANGES IN PRICE

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

CRITICAL ACCOUNTING POLICIES AND ESTIMATES

The following summarizes several of our critical accounting policies. See a complete list of significant accounting policies in Note 2 to the Consolidated Financial Statements.

Use of Estimates

The preparation of financial statements in conformity with generally accepted accounting principles requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities at the date of the 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 natural gas and oil properties through depletion and the full cost ceiling test, as discussed in more detail below.

Natural Gas and Oil 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 $0.7 million and $1.1 million for the nine months ended September 30, 2002 and 2003, 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. The depletion rate per thousand cubic feet equivalent (Mcfe) for the nine months ended September 30, 2002 and 2003 was $1.40 and $1.51, 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 natural gas and oil properties are subject to a ceiling test, which limits such costs to the estimated present value, discounted at a 10% interest rate, of future net revenues from proved reserves (the NPV) based on current economic and operating conditions (with reserve estimates calculated using SEC guidelines). This test is performed after any impairment of unproved properties are

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added to the property costs to amortize as discussed above. We include asset retirement obligation costs, liabilities and related discounted cash flows in our ceiling test calculations. If net capitalized costs exceed this limit, we charge the excess to operations through depreciation, depletion and amortization. No write-down of our natural gas and oil assets was necessary for the nine months ended September 30, 2002 or 2003. In concert with this determination, a price sensitivity study also indicated that a 20% increase in commodity prices at September 30, 2003 would have increased our NPV by approximately $15.8 million. Conversely, a 20% decrease in commodity prices at September 30, 2003 would have reduced our NPV by approximately $18.4 million. This would have caused our unamortized cost of proved natural gas and oil properties to exceed the cost pool ceiling by approximately $18.1 million. Our aforementioned price sensitivity and NPV is as of September 30, 2003 and, accordingly, does not include any potential changes in reserves due to fourth quarter performance, such as commodity prices, reserve revisions and drilling results, including proved reserves associated with our recently discovered Shadyside #1 well. Based on natural gas and oil prices in effect on December 31, 2001, the unamortized cost of natural gas and oil properties exceeded the cost center ceiling. As permitted by full cost accounting rules, improvements in pricing subsequent to December 31, 2001 removed the necessity to record a write-down. Using prices in effect on December 31, 2001 the pretax write-down would have been approximately $0.7 million. Because of the volatility of natural gas and oil prices, we cannot assure you that we will not experience a write-down in future periods.

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.

We have a significant amount of proved undeveloped reserves, which are primarily oil reserves. We had 41.9 Bcfe of proved undeveloped reserves, representing 66% of our total proved reserves at December 31, 2002. These reserves are primarily attributable to our Camp Hill properties we acquired in 1994. This ratio of proved undeveloped reserves to total proved reserves and the producing properties that have had an average productive life of 2.25 years since our inception, compared to the average 10 year depletable life for the total proved reserves, has resulted in a relatively low historical depletion rate and depreciation 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. It has also resulted in the build-up of nondepleted capitalized costs associated with properties that have been completely produced out.

We expect our 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 and current prices were both 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.

SFAS No. 141, "Business Combinations," and SFAS No. 142, "Goodwill and Intangible Assets," were issued by the FASB in June 2001 and became effective for us on July 1, 2001 and January 1, 2002, respectively. SFAS No. 141 requires all business combinations initiated after June 30, 2001 to be accounted for using the purchase method. Additionally, SFAS No. 141 requires companies to disaggregate and report separately from goodwill certain intangible assets. SFAS No. 142 establishes new guidelines for accounting for goodwill and other intangible assets. Under SFAS No. 142, goodwill and certain other intangible assets are not amortized but rather are reviewed annually for impairment.

Natural gas and oil mineral rights held under lease and other contractual arrangements representing the right to extract such reserves for both undeveloped and developed leaseholds may have to be classified separately from natural gas and oil properties as intangible assets on our consolidated balance sheets. In addition, the disclosures required by SFAS No. 141 and 142 relative to intangibles would be included in the notes to the consolidated financial statements. Historically, we, like many other natural gas and oil

companies, have included these rights as part of natural gas and oil properties, even after SFAS No. 141 and 142 became effective.

As it applies to companies like us that have adopted full cost accounting for natural gas and oil activities, we understand that this interpretation of SFAS No. 141 and 142 would only affect our balance sheet classification of proved natural gas and oil leaseholds acquired after June 30, 2001 and all of our unproved natural gas and oil leaseholds. We would not be required to reclassify proved reserve leasehold acquisitions prior to June 30, 2001 because we did not separately value or account for these costs prior to the adoption date of SFAS No. 141. Our results of operations and cash flows would not be affected, since these natural gas and oil mineral rights held under lease and other contractual arrangements representing the right to extract natural gas and oil reserves would continue to be amortized in accordance with full cost accounting rules.

As of September 30, 2003, December 31, 2002 and December 31, 2001, we had leasehold costs incurred of approximately $3.4 million, $1.4 million and $1.4 million, respectively, that would be classified on our consolidated balance sheet as "intangible leasehold costs" if we applied the interpretation discussed above.

We will continue to classify our natural gas and oil mineral rights held under lease and other contractual rights representing the right to extract such reserves as tangible oil and gas properties until further guidance is provided.

Natural Gas and Oil Reserve Estimates

The reserve data included or incorporated in this prospectus are estimates prepared by Ryder Scott Company and Fairchild and 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 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 natural gas and oil 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 have based our 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.

Derivative Instruments and Hedging Activities

In June 1998, the FASB issued SFAS No. 133, "Accounting for Derivative Instruments and Hedging Activities." This statement, as amended by SFAS No. 137 and SFAS No. 138, establishes standards of accounting for and disclosures of derivative instruments and hedging activities. This statement requires all derivative instruments to be carried on the balance sheet at fair value with changes in a derivative instrument's fair value recognized currently in earnings unless specific hedge accounting criteria are met. SFAS No. 133 was effective for us beginning January 1, 2001 and we adopted it on that date. In accordance with the current transition provisions of SFAS No. 133, we recorded a cumulative effect transition adjustment of $2.0 million (net of related tax expense of $1.1 million) in accumulated other comprehensive income to recognize the fair value of our derivatives designated as cash flow hedging instruments at the date of adoption.

Upon entering into a derivative contract, we designate the derivative instruments as a hedge of the variability of cash flow to be received (cash flow hedge). Changes in the fair value of a cash flow hedge are recorded in other comprehensive income to the extent that the derivative is effective in offsetting changes in the fair value of the hedged item. Any ineffectiveness in the relationship between the cash flow hedge and the hedged item is recognized currently in income. Gains and losses accumulated in other comprehensive income associated with the cash flow hedge are recognized in earnings as natural gas and oil revenues when the forecasted transaction occurs. All of our derivative instruments at December 31, 2002 and September 30, 2003 were designated and effective as cash flow hedges except for certain options described below under "--Qualitative and Quantitative Disclosures About Market Risk--Derivative Instruments and Hedging Activities."

When we discontinue hedge accounting because it is probable that a forecasted transaction will not occur, we continue to carry the derivative on the balance sheet at its fair value and immediately recognize in earnings any gains and losses that were accumulated in other comprehensive income. In all other situations in which we discontinue hedge accounting, we will carry the derivative at fair value on our balance sheet and will recognize in future earnings any future changes in its fair value.

We typically use fixed rate swaps and costless collars to hedge our exposure to material changes in the price of natural gas and oil. We formally document all relationships between hedging instruments and hedged items as well as our risk management objectives and strategy for undertaking various hedge transactions. This process includes linking all derivatives that are designated cash flow hedges to forecasted transactions. We also formally assess, both at the hedge's inception and on an ongoing basis, whether the derivatives that are used in hedging transactions are highly effective in offsetting changes in cash flows of hedged transactions.

Our Board of Directors sets our hedging policy, including volumes, types of instruments and counterparties, on a quarterly basis. Management implements these policies through the execution of trades by either the President or Chief Financial Officer after consultation with and concurrence by the other as well as the Chairman of the Board. The master contracts with the authorized 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 hedging activities quarterly.

Income Taxes

Under SFAS No. 109, "Accounting for Income Taxes," we recognize deferred income taxes 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 establish valuation allowances when necessary to reduce the deferred tax asset to the amount expected to be realized.

Contingencies

We recognize liabilities and other contingencies upon our determination 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.

NEW ACCOUNTING PRONOUNCEMENTS

The FASB issued Interpretation 46, "Consolidation of Variable Interest Entities" (FIN 46), in January 2003. FIN 46 requires the consolidation of specified types of entities in which a company absorbs a majority of another entity's expected losses, receives a majority of the other entity's expected residual returns, or both, as a result of ownership, contractual or other financial interests in the other entity. These entities are called "variable interest entities." The provisions of FIN 46 were effective for us in the second quarter for new transactions or entities formed in 2003 and in the third quarter for transactions or entities formed prior to 2003.

If an entity is determined to be a "variable interest entity" (VIE), the entity must be consolidated by the "primary beneficiary." The primary beneficiary is the holder of the variable interests that absorbs a majority of the variable interest entity's expected losses or receives a majority of the entity's residual returns in the event no holder has a majority of the expected losses. The primary beneficiary is determined based on projected cash flows at the inception of the variable interests.

We have assessed whether to consolidate Pinnacle under FIN 46. Because Steven A. Webster, our Chairman, is also a managing director of Credit Suisse First Boston (whose interest in Pinnacle is described under "Business and Properties--Pinnacle Transaction") we could be defined as the primary beneficiary if the projected cash flows analysis indicated losses in excess of the equity invested. The initial determination of whether an entity is a VIE is to be reconsidered only when one or more of the following occur:

- the entity's governing documents or the contractual arrangements among the parties involved change;

- the equity investment of some part thereof is returned to the investors, and other parties become exposed to expected losses; or

- the entity undertakes additional activities or acquires additional assets that increase the entity's expected losses.

We have determined that we should not consolidate Pinnacle under FIN 46 because our current projected cash flow analysis of Pinnacle's operations at inception indicates that Pinnacle is not a VIE. Accordingly, our investment in Pinnacle has been recorded using the equity method of accounting.

The reclassification of investments in contributed properties resulting from the transaction with Pinnacle is reflected on our balance sheet as of September 30, 2003 in accordance with the full cost method of accounting.

QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

Commodity Price Risk

Our major market risk exposure is the commodity pricing applicable to our natural gas and oil 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. Those prices are and are expected to continue to be volatile. See "Risk Factors--Natural gas and oil prices are highly volatile, and lower prices will negatively affect our financial results." A 10% fluctuation in the price received for natural gas and oil production would have an approximate $2.7 million and $3.0 million impact on our annual revenues and operating income for the year ended December 31, 2002 and the nine months ended September 30, 2003, respectively.

Derivative Instruments and Hedging Activities

To mitigate some of our commodity price risk, we engage periodically in certain limited hedging activities but only to the extent of buying protection price floors. We record the costs and any benefits derived from these price floors as a reduction or increase, as applicable, in natural gas and oil sales revenue; these reductions and increases were not significant for any year presented in the financial information included or incorporated in this prospectus. The costs to purchase put options are amortized over the option period. We do not hold or issue derivative instruments for trading purposes. We realized losses related to these instruments of $0.4 million and $1.8 million for the nine months ended September 30, 2002 and 2003, respectively.

As of December 31, 2002 and September 30, 2003, $0.4 million and $67,000, net of tax of $0.2 million and $36,000, respectively, remained in accumulated other comprehensive income related to the valuation of our hedging positions.

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 hedging 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 be exposed again to price risk. We have some 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 hedging 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 gas derivative transactions are generally settled based upon the average of the reporting settlement prices on the NYMEX 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 NYMEX for each trading day of a particular calendar month. For the month of December 2002 a $0.10 change in the price per Mcf of gas sold would have changed revenue by $44,000. A $0.70 change in the price per barrel of oil would have changed revenue by $41,000.

The table below summarizes our total natural gas production volumes subject to derivative transactions during 2002 and the weighted average NYMEX reference price for those volumes.

	NATURAL GAS SWAPS
Volumes (MMBtu)....................	2,131,000
Average price ($/MMBtu)...........	$3.20

	NATURAL GAS CAPS
Volumes (MMBtu)....................	183,000
Average price ($/MMBtu)	
Floor.........................	$3.50
Ceiling.......................	$4.52

The table below summarizes our total crude oil production volumes subject to derivative transactions during 2002 and the weighted average NYMEX reference price for those volumes.

	CRUDE OIL SWAPS
Volumes (Bbls).................	131,600
Average price ($/Bbls).........	$ 25.52

Total oil purchased and sold under swaps and collars during the three months ended September 30, 2002 and 2003 were 33,600 Bbls and 24,400 Bbls, respectively. Total natural gas purchased and sold under swaps and collars during the three months ended September 30, 2002 and 2003 was 731,000 MMBtu and 828,000 MMBtu, respectively. Total oil purchased and sold under swaps and collars during the nine months ended September 30, 2002 and 2003 was 79,100 Bbls and 150,700 Bbls, respectively. Total natural gas purchased and sold under swaps and collars during the nine months ended September 30, 2002 and 2003 was 3,094,000 MMBtu and 2,187,000 MMBtu, respectively. We realized net losses under these hedging arrangements of $0.1 million and $0.1 million for the three months ended September 30, 2002 and 2003, respectively, and $0.4 million and $1.7 million for the nine months ended September 30, 2002 and 2003, respectively.

At December 31, 2002 and September 30, 2003, we had the following outstanding hedge positions:

DECEMBER 31, 2002

QUARTER	CONTRACT VOLUMES BBLS	CONTRACT VOLUMES MMBTU	AVERAGE FIXED PRICE	AVERAGE FLOOR PRICE	AVE CEILIN
First Quarter 2003..................	27,000		$24.85		
First Quarter 2003..................	36,000			$23.50	$26
First Quarter 2003..................		540,000		3.40	5
Second Quarter 2003.................	27,300		24.85		
Second Quarter 2003.................	36,000			23.50	26
Second Quarter 2003.................		546,000		3.40	5
Third Quarter 2003..................		552,000		3.40	5
Fourth Quarter 2003.................		552,000		3.40	5

SEPTEMBER 30, 2003

QUARTER	CONTRACT VOLUMES BBLS	CONTRACT VOLUMES MMBTU	AVERAGE FIXED PRICE	AVERAGE FLOOR PRICE	AVE CEILIN
Fourth Quarter 2003.................	30,700		$30.22		
Fourth Quarter 2003.................		552,000		$3.40	$5
First Quarter 2004..................		546,000		4.10	7
Second Quarter 2004.................		273,000		4.00	5
Third Quarter 2004..................		276,000		4.00	5
Fourth Quarter 2004.................		93,000		4.00	5

From October 1, 2003 through January 12, 2004, we entered into swap arrangements covering 51,500 Bbls of oil for November 2003 through May 2004 production with an average fixed price of $30.33. We also entered into swap arrangements covering 180,000 MMBtu of natural gas for January 2004 through February 2004 production with an average fixed price of $6.67 and costless collar arrangements covering 825,000 MMBtu of natural gas production for April 2004 through December 2004 with a floor of $4.00 and a ceiling of $6.00.

In addition to the hedge positions above, during the second quarter of 2003, we acquired call options to sell 6,000 MMBtu of natural gas per day for the period July 2003 through August 2003 (552,000 MMBtu) at $8.00 per MMBtu for approximately $119,000. We acquired these options to protect our cash position against potential margin calls on certain natural gas derivatives due to large increases in the price of natural gas. We expensed $119,000 related to the expiration of these options during the nine months ended September 30, 2003.

Interest Rate Risk

Our floating rate debt exposes us to changes in interest rates. With regard to our revolving credit facility, a 10% fluctuation in short-term interest rates would have impacted our 2002 cash flow by approximately $32,000.

Financial Instruments and Debt Maturities

Our financial instruments consist of cash and cash equivalents, accounts receivable, accounts payable, bank borrowing, senior subordinated notes payable and Series B redeemable preferred stock. 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 September 30, 2002 and 2003, and were determined based upon interest rates currently available to us for borrowings with similar terms. Maturities of the debt are $1.6 million in 2003, $3.9 million in 2004, $8.5 million in 2005 and the balance in 2007.

BUSINESS AND PROPERTIES

Certain terms used in this section relating to the natural gas and oil industry are defined in the "Glossary of Certain Oil and Gas Terms" in this prospectus. Unless explicitly stated otherwise, or the context otherwise requires, all references in this section to planned capital expenditures or planned drilling activities assume the completion of this offering.

GENERAL

We are 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 in Texas and Louisiana, primarily in the Miocene, Wilcox, Frio and Vicksburg trends. Our other interests include properties in East Texas, a coalbed methane investment in the Rocky Mountains and, recently, the Barnett Shale trend in North Texas. Additionally, in 2003 we obtained licenses to explore in the U.K. North Sea.

We have grown our production through our 3-D seismic-driven exploratory drilling program. Our compound production growth rate for the period December 31, 1999 through September 30, 2003 on an annualized basis was 19%. From our inception through September 30, 2003, we participated in the drilling of 285 wells (88.0 net) with a success rate of approximately 67% in our onshore Gulf Coast core area. Exploratory wells accounted for 97% of the total wells we drilled. Our total proved reserves as of December 31, 2002 were an estimated 63.2 Bcfe with a PV-10 Value of $83.6 million. During 2002, we added 11.4 Bcfe to proved reserves and produced 7.2 Bcfe.

As a main component of our business strategy, we have acquired licenses for over 8,700 square miles of 3-D seismic data for processing and evaluation. Since

2001, we have been able to increase the size of our 3-D seismic holdings in our onshore Gulf Coast core area by approximately 75% to over 6,650 square miles, in large part by taking advantage of very favorable pricing available for nonproprietary data. 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, ARCO, Conoco, Vastar Resources, Pennzoil and Tenneco. Using 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 September 30, 2003, we had 85,678 gross acres in Texas and Louisiana under lease or lease option, almost all of which is covered by 3-D seismic data. On this leased acreage, we have identified over 120 potential exploratory drilling locations, including over 45 additional extension opportunities, depending on the success of our initial drilling activities on those locations. The vast majority of our 3-D seismic data covers productive geological trends in our onshore Gulf Coast core area, where we have made 192 completions as a result of our utilization and evaluation of this data.

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 core area of 72% over the last three years. We are drilling or plan to drill approximately 32 wells (15.5 net) in the

onshore Gulf Coast area during 2004. We have budgeted approximately $40 to 45 million for capital expenditures in 2004, $37.7 million of which we expect to use for drilling activities in the onshore Gulf Coast area.

- Focus on Prolific and Industry-Proven Trends. We focus our activities primarily in the prolific onshore Gulf Coast area where our management, our technical staff and our field operations teams have significant prior experience. Although we have broadened our areas of operations to include the Rocky Mountains and have purchased interests in the Barnett Shale trend and the U.K. North Sea, we plan to focus a majority of our near-term capital expenditures in the onshore Gulf Coast region, where we believe our accumulated data and knowledge base provide a competitive advantage.

- 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 trends of our onshore Gulf Coast region. In 2003, we added approximately 1,050 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. As of September 30, 2003, we had accumulated licenses for approximately 8,700 square miles of 3-D seismic data and identified over 210 drilling locations and extension opportunities, including 123 currently under lease or in the process of being leased.

- 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 will continue to expand our exploratory drilling portfolio, including possibly through 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. 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 18 natural gas and oil professionals, including geophysicists, petrophysicists, geologists, petroleum engineers and production and reserve engineers, who have an average of over 20 years of experience. This level of expertise and experience gives us a unique in-house ability to apply advanced technologies to our drilling and production activities. Our technical staff is granted stock options and participates in an incentive bonus pool based on production resulting from our exploratory successes.

SIGNIFICANT AREAS

For the period from January 1, 2000 through December 31, 2002, we completed 61 wells (18.8 net) in 84 attempts for a success rate of 73%. Total exploration, development and acquisition activities from January 1, 2000 through December 31, 2002 resulted in the addition of approximately 26.4 Bcfe, net to our interest.

We have budgeted approximately $40 to $45 million to drill approximately 38 wells (18.5 net) and to purchase and reprocess 3-D seismic surveys during 2004. See "Management's Discussion and Analysis of Financial Condition and Results of Operations--Liquidity and Capital Resources." The following chart summarizes our properties by region and focus area as of September 30, 2003 unless otherwise noted.

	THREE MONTHS ENDED SEPTEMBER 30, 2003		AT SEPTEMBER 30, 2003				
	AVERAGE DAILY NET PRODUCTION (MMCFE/D)	% NAT. GAS	PRODUCTIVE WELLS GROSS	PRODUCTIVE WELLS NET	3-D SEISMIC DATA (SQ. MILES)	NET OPTIONS/ LEASED ACRES	BUDGETE ESTIMATED

Onshore Gulf Coast:							
Wilcox.................	1.6	94	28	8.2	1,793	18,741	$ 5.7
Frio/Vicksburg.........	8.4	58	137	43.3	2,102	8,615	5.4
Southeast Texas........	8.8	78	11	3.8	900	3,729	3.8
South Louisiana........	2.4	58	7	1.3	1,864	2,028	3.6
East Texas...............	0.4	-	45	5.9	472	2,816	0.7
Rocky Mountain...........	-	-	-	-	473	27,140	-
Barnett Shale............	-	-	-	-	-	1,409	0.6
North Sea................	-	-	-	-	153	209,613	-
Other Areas..............	-	-	-	-	980	-	-
Total..................	21.6	68	228	62.5	8,737	274,091	$19.8

Core Project Area--The Onshore Gulf Coast Region

The onshore Gulf Coast region is a prolific proven hydrocarbon trend with complex structural and stratigraphic targets that are optimally explored through the use of 3-D seismic data. We believe our approximately 6,650 square miles of data located in key producing onshore Gulf Coast trends is comparable to the volume of data some major oil and gas companies hold for this area. Of this volume, approximately 2,870 square miles of 3-D seismic data was acquired or reprocessed in the last 18 months. Our exploration staff, with an average of over 20 years experience, analyzes the data seeking to provide multiple opportunities which we prioritize and add to our onshore Gulf Coast exploration prospect portfolio.

Wilcox Trend

We have licenses for approximately 1,800 square miles of 3-D seismic data and 18,741 acres of leasehold in the Wilcox trend in Texas. From January 1, 2000 through December 31, 2003, we drilled and completed 32 wells (9.8 net) on 40 attempts in this area. We invested $4.3 million to drill and complete seven wells (1.9 net) in the Texas Wilcox area in 2003 and expect to devote approximately $8.0 million to drill seven wells (3.9 net) in this area in 2004. Currently, we have identified over 30 exploratory drilling locations, with an additional 22 potential extension opportunities, in the Wilcox trend over which we have licenses for 3-D seismic data and leased acreage. Approximately 18 of the 30 exploratory locations we have identified are relatively lower risk and generally shallower with the remainder being relatively higher risk and deeper with greater upside potential.

Greater Cabeza Creek. Since January 1, 2000, our exploration efforts in the Wilcox area largely have been focused in the greater Cabeza Creek area centered in Goliad, Lavaca and Dewitt Counties, where we have licenses for over 950 square miles of 3-D seismic data and 5,700 net acres of leasehold. From January 1, 2000 through December 31, 2003, we have drilled 14 wells (7.1 net) with an 86% success rate in this area. Our most notable discovery was the Riverdale Field in 2001, where we have 68.8% working interest. The Riverdale Field was delineated with two extension wells. The greater Cabeza Creek area continues to be a primary focus area in the middle and lower Wilcox intervals which have relatively higher potential and

risk. We have a significant acreage position to either explore ourselves or sell to third parties while retaining a promoted interest.

Texas Frio/Vicksburg Trend Area

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 2,100 miles of 3-D seismic data and 8,615 net leasehold acres over this trend. Since 1999, we have focused primarily in Matagorda County, the location of the Providence Field, and in Brooks County, the location of the Encinitas Field.

Currently, we have identified over 23 exploratory drilling locations with an additional 12 potential extension opportunities (depending on the success of our initial drilling activities on those locations) in the Frio/ Vicksburg trend area over which we have licenses for 3-D seismic data and leased acreage. Approximately 15 of the 23 exploratory locations we have identified are relatively lower risk and generally shallower with the remaining eight being relatively higher risk and deeper with greater upside potential.

From January 1, 2000 through December 31, 2003, we have drilled and completed 38 wells (10.0 net) in 45 attempts in this trend. We invested $6.1 million to drill and complete 16 wells (3.4 net) in the Frio/ Vicksburg trend area in 2003 and expect to devote approximately $11.0 million to drill 12 wells (5.0 net) in this area in 2004.

Providence Field. We have licenses for over 540 square miles of 3-D data (including 450 square miles of newly reprocessed data delivered in 2003) in and surrounding the Providence Field we discovered in 2001. Since the discovery well commenced production in January 2002, five wells have been drilled and successfully completed. Four of the wells had average production rates ranging from 14,309 to 17,669 Mcfe per day per well during the first 90 full days of production. The field has cumulative production as of September 30, 2003 of 10.2 Bcfe. We have working interests ranging from 35% to 45% in the leases in this field and operate three of the six wells. We anticipate participating in two additional extension wells (1.0 net) in the field in first quarter 2004.

Encinitas Field. This field, the site of our first 3-D seismic survey in 1995, has 24 wells currently producing. Since 1996, we have participated in the drilling of 24 wells (4.0 net) in this area, 22 (3.5 net) of which were successfully completed. During 2003, we participated in the drilling of nine wells, all of which were successfully completed. We expect to drill between four and eight wells in 2004, with an additional six to 10 well locations to be drilled thereafter. We will have a 27.5% working interest in those wells.

Southeast Texas Area

The Southeast Texas area contains similar objective levels found in the Frio/Vicksburg trend area. We separate this as a focus area because of the geographic concentration of our 3-D seismic data and because reservoirs in this area can 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 900 square miles of 3-D data (including 400 square miles of newly released data delivered in 2003) over our Southeast Texas project area which is focused primarily on the Frio, Yegua, Cook Mountain and Vicksburg formations. The project area is split into the Cedar Point and Liberty County areas.

Currently, we have identified over 15 exploratory drilling locations with an additional 10 potential extension locations in the Southeast Texas area over which we have licenses for 3-D seismic data. Approximately 12 of the 15 exploratory locations we have identified are relatively lower risk and generally shallower with the remaining three being relatively higher risk and deeper with greater upside potential.

From January 1, 2000 to December 31, 2003, we participated in the drilling and completion of 12 wells (4.3 net)in 17 attempts in this area. We invested $2.0 million to drill and complete four wells (1.2 net) in

the Southeast Texas area in 2003 and expect to devote approximately $11.1 million to drill 11 wells (4.8 net) in this area in 2004. 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 the remainder of 2003 and for 2004.

Cedar Point Area. The Cedar Point Project Area is located in Chambers County, Texas, adjacent to Trinity Bay. The 30-square-mile 3-D survey targets the lower Frio and Vicksburg formations. Since 1999, five of six wells drilled have been successful. In 2003, we drilled one well that produced an average of 15,789 Mcfe per day during the first 90 full days of production. In December 2003, we completed an extension well that encountered approximately 41 feet of logged pay. Our working interest in leases in this project area is approximately 28% in the first well drilled in 2003 and 25% in the extension well.

Liberty County Area. We have identified and leased prospects ranging from the Frio to the Cook Mountain formations within the 500 square miles of 3-D seismic data in the Liberty Project Area which, along with 290 square miles of newly released 3-D seismic data licensed in early 2003, now covers significant areas of Liberty and Hardin Counties, Texas. Since January 1, 2000, we have been successful on six of eight wells drilled, including one Yegua well, one Frio well and five Cook Mountain wells. In 2002, we completed one well that produced an average of 9,787 Mcfe per day during the first 90 full days of production. We operate this well and own a 40% working interest. In 2003, we had another drilling success in this area with a well producing an average of 13,030 Mcfe per day during the first 90 full days of production. We operate this well and own a 46.3% working interest.

South Louisiana Area

The South Louisiana area primarily contains objectives in the Middle and Lower Miocene intervals. We have acquired licenses for approximately 1,850 square miles of 3-D data (including 1,416 square miles of newly released data delivered in 2003), and over 2,000 acres of leasehold. The 3-D seismic data sets are concentrated in one general area including St. Mary, Terrebonne and LaFourche Parishes.

Currently, we have identified over eight exploratory drilling locations with an additional three potential extension locations in the South Louisiana area over which we have licenses for 3-D seismic data. Two of the eight exploratory locations we have identified are relatively lower risk and generally shallower with the other six being relatively higher risk and deeper with greater upside potential. From January 1, 2000 to December 31, 2003, we drilled and completed seven wells (1.7 net) on 14 attempts in this area. We invested $3.2 million to drill three wells (0.1 net) in the South Louisiana area in 2003 and expect to devote approximately $9.3 million to drill five wells (2.5 net) in this area in 2004.

LaRose Area. During 2002, we successfully drilled and completed an offset well to the discovery well in this area. We operate the two wells and own a 40% working interest. The discovery well produced at an average of 15,581 Mcfe per day during the first 90 full days of production. We plan to participate in three to four additional wells (1.3 to 1.8 net) in the general area during 2004.

Patterson Area. In December 2003, we announced the discovery of Shadyside #1 well in this area, which logged over 77 feet of pay. We operate the well and have an approximate 35% working interest. We believe there are two potential extension wells in the Patterson area.

Other Areas of Interest

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 470 square miles of 3-D seismic data in the East Texas area and 2,816 net acres under leasehold.

We did not drill any wells in the East Texas area in the first nine months of 2003 and expect to devote approximately $0.7 million to drill one (0.5 net) well in this region in the last three months of 2003 and in 2004.

Camp Hill Field. We own interests in eight leases totaling approximately 600 gross acres in the Camp Hill field in Anderson County, Texas. We currently operate seven of these leases. During the year ended December 31, 2002, the project produced an average of 58 Bbls/d of 19 API gravity oil. The wells produce from a depth of 500 feet and utilize a tertiary steam drive as an enhanced oil recovery process. Although efficient at maximizing oil recovery, the steam drive process is relatively expensive to operate because natural gas or produced crude is burned to create the steam injectant. Lifting costs during the year ended December 31, 2002 averaged $14.99 per barrel ($2.50 per Mcfe). In response to high fuel gas prices, steam injection was reduced in mid-2000. Because profitability increases when natural gas prices drop relative to oil prices, the project is a natural hedge against decreases in natural gas prices relative to oil prices. The oil produced, although viscous, commands a higher price (an average premium of $1.00 per Bbl during the year ended December 31, 2002) than West Texas intermediate crude due to its suitability as a lube oil feedstock. As of December 31, 2002, we had 7.7 MMBbls of proved oil reserves in this project, with 750 MBbls of oil reserves currently developed. 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 potential higher rates of return, adding to our lease position in this field and further evaluating additional economic enhancements for this field's development. The proved undeveloped reserves at the Camp Hill Field constitute 66% of our proved reserves and account for 34% of our present value of net future revenues from proved reserves as of December 31, 2002. We anticipate drilling additional wells and increasing steam injection to develop the proved undeveloped reserves in this project, with the timing and amount of expenditures dependent on the relative prices of oil and natural gas. We have an average working interest of approximately 90% in this field and an average net revenue interest of 74%.

Tortuga Grande Prospect. In November 2003 we finalized an agreement to operate the re-entry of an abandoned Cotton Valley test well that calculates on logs to have over 230 feet of sands with possible production. At the time of drilling, the operator perforated the objective interval and tested gas but in uneconomic volumes. This well was drilled before newer fracturing technology that can increase flow rates was developed and when gas prices were significantly lower. Following successful testing of this re-entry, there are over 10 potential extension locations on our acreage that may be prospective.

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. Since that time, we have acquired leases on 2,178 net acres and have transactions pending on additional acreage. We have participated in the drilling of four wells (1.6 net), two of which are completed and producing and two of which are awaiting pipeline hookup. Our total capital expenditures as of November 21, 2003 on these wells have been $0.6 million. Current net production from the two wells (1.0 net) drilled to date that are on-line is a combined 360 Mcf per day and 384 Mcfe per day as of November 21, 2003. We have received permits for the first proposed well for which we will act as operator, a horizontal well expected to be drilled in the first quarter of 2004. We are continuing to expand our leasehold acquisition in this trend. See "Management's Discussion and Analysis of Financial Condition and Results of Operations--Recent Developments--Potential Barnett Shale Acquisition."

Rocky Mountain Region

As discussed below under "--Pinnacle Transaction," in the second quarter of 2003, we contributed to Pinnacle our interests in leases in the Clearmont, Kirby, Arvada and Bobcat project areas and natural gas and oil reserves in the Bobcat project in the Powder River Basin in southwestern Wyoming and Montana. We also own direct interests in approximately 189,000 gross acres of coalbed methane properties in the Castle Rock project area in Montana and the Oyster Ridge project area in Wyoming that were not

contributed to Pinnacle, but we currently have no proved reserves of, and are no longer receiving revenue from, coalbed methane gas other than through Pinnacle.

As of the closing of the Pinnacle transaction in June 2003, we had participated in the acquisition and/or drilling of 75 wells (28.0 net); we had invested $0.6 million to drill and complete two wells in the Rocky Mountain region from January 1, 2003 to that date. All of the wells encountered coal accumulations and are in various stages of development and/or stages of production. 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.

We continue to own a 26.9% interest in Pinnacle on a fully diluted basis. We are not required to make any further capital contributions to Pinnacle.

Of the approximately 318,740 gross and 90,250 net mineral acres held by us and Pinnacle, respectively, as of September 30, 2003, approximately 193,250 and 20,970 net mineral acres, respectively, are located in the State of Montana. The issuance of new coalbed methane drilling permits in Montana was halted temporarily pending the Federal Bureau of Land Management's 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. Accordingly, the Montana Board of Oil and Gas Conservation has begun accepting new coalbed methane drilling permit applications. Environmental groups have initiated two lawsuits, each challenging one of these program approvals. We believe that the decisions by the Federal Bureau of Land Management and the State of Montana ultimately will be upheld and new coalbed methane development will continue to be authorized in Montana. Pinnacle holds approximately 56 grandfathered drilling permits in Montana that were contributed by our joint venture partner RMG at the time of Pinnacle's formation, and RMG holds approximately 56 grandfathered drilling permits in Montana for acreage in which CCBM also has an interest. There can be no assurance that any new permits will be obtained in a given time period or at all.

U.K. North Sea Region

We have been awarded seven acreage blocks, consisting of one "Traditional" and three "Promote" licenses, in the United Kingdom's 21st Round of Licensing. The awarded blocks, to explore for natural gas and oil totaling approximately 209,000 acres, are located within mature producing areas of the Central and Southern North Sea in water depths of 30 to 350 feet. The Promote licenses do not have drilling commitments and have two-year terms. The Traditional license will be canceled after four years if we or our assignee elects not to commit to drilling a well. We believe our U.K. North Sea interest is a natural extension to our technical analyses, portfolio and business plan. The U.K. North Sea includes proven hydrocarbon trends with established technological expertise, available large 3-D seismic datasets and significant exploration potential. We plan to promote our interests to other parties experienced in drilling and operating in this region. Geological and geophysical costs will be incurred in an attempt to maximize the value of our retained interest. Our estimated project commitments from commencement through mid-2005 are $0.9 million, comprised of $0.2 million for seismic data, $0.2 million for leasehold costs and $0.2 million for data processing in 2003 and $0.3 million for seismic data processing in 2004.

WORKING INTEREST AND DRILLING IN PROJECT AREAS

The actual working interest we ultimately will 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 on 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.

Our success will be materially dependent upon the success of our exploratory drilling program. In addition, although we currently are pursuing prospects within the project areas described above, there can be no assurance that these prospects will be drilled at all or within the expected time frame. See "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" and "Risk Factors--We may not adhere to our proposed drilling schedule."

NATURAL GAS AND OIL RESERVES

The following table sets forth our estimated net proved natural gas and oil reserves and the PV-10 Value of such reserves as of December 31, 2002. The reserve data and the present value as of December 31, 2002 were prepared by Ryder Scott Company and Fairchild and Wells, Inc., Independent Petroleum Engineers. For further information concerning Ryder Scott's and Fairchild's estimate of our proved reserves at December 31, 2002, see the reserve reports included as Appendix A to this prospectus. 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 natural gas and oil reserves we own. For further information concerning the present value of future net revenue from these proved reserves, see Note 13 of the notes to our consolidated financial statements for the year ended December 31, 2002, which are included in this prospectus.

	PROVED RESERVES		
	DEVELOPED	UNDEVELOPED	TOTAL
Natural gas (MMcf)	12,826	96	12,922
Oil and condensate (MBbls)	1,393	6,988	8,381
Natural gas equivalent (MMcfe)	21,184	42,024	63,208
PV-10 Value (in thousands)(1)	$55,235	$28,379	$83,614

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(1) The PV-10 Value as of December 31, 2002 is pretax and was determined by using the December 31, 2002 sales prices, which averaged $29.16 per Bbl of oil, $4.70 per Mcf of natural gas.

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

For a discussion of the uncertainties inherent in estimating natural gas and oil reserves and their estimated values, see "Risk Factors--Our reserve data and estimated discounted future net cash flows are estimates based on assumptions that may be inaccurate and on existing economic and operating conditions that may differ from future conditions."

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VOLUMES, PRICES AND NATURAL GAS & OIL 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 natural gas and oil for the periods indicated. The table includes the cash impact of hedging activities and the effect of certain hedge positions with an affiliate of Enron Corp. reclassified as derivatives during November 2001.

	YEAR ENDED DECEMBER 31,		
	2000	2001	2002

PRODUCTION VOLUMES:			
Natural gas (MMcf)	5,460	4,432	4,801
Oil (MBbls)	198	160	401
Natural gas equivalent (MMcfe)	6,651	5,390	7,207
AVERAGE SALES PRICES:(1)			
Natural gas (per Mcf)	3.90	5.04	3.50
Oil (per Bbl)	$27.81	$24.28	$24.94
NATURAL GAS AND OIL OPERATING EXPENSES (PER MCFE):(2)			
Operating expenses in all areas excluding Camp Hill	$ 0.59	$ 0.43	$ 0.44
Operating expenses in Camp Hill	3.08	2.14	2.50
Total operating expenses	$ 0.74	$ 0.77	$ 0.68

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(1) Includes impact of hedging activities.
(2) Includes direct operating costs (labor, repairs and maintenance, materials and supplies), workover costs and the administrative costs of production offices, insurance and property and severance taxes.

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,		
	2000	2001	2002
	(in thousands)		
Acquisition costs:			
Unproved properties(1)	$ 6,641	$12,607	$ 6,402
Proved properties	337	800	660
Exploration	7,843	18,356	14,194
Development	1,361	3,065	2,351
Total costs incurred(2)	$16,182	$34,828	$23,607

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(1) Includes unproved property costs of $9.0 million in 2001 and $2.2 million in 2002 in the coalbed methane properties we contributed as a minority interest to Pinnacle in June 2003.
(2) Excludes capitalized interest on unproved properties of $3.6 million, $3.2 million and $3.1 million for the years ended December 31, 2000, 2001 and 2002, respectively.

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DRILLING ACTIVITY

The following table sets forth our drilling activity for the years ended December 31, 2000, 2001 and 2002. 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, 2002 has resulted in a commercial success rate of approximately 66%.

	YEAR ENDED DECEMBER 31,					
	2000		2001		2002	
	GROSS	NET	GROSS	NET	GROSS	NET
Exploratory wells:						
Productive	19	4.7	18	5.9	16	4.6
Nonproductive	15	3.4	5	1.4	3	1.1
Total	34	8.1	23	7.3	19	6.7
Development wells:						
Productive	5	1.9	2	0.3	1	0.4
Nonproductive	-	-	-	-	-	-
Total	5	1.9	2	0.3	1	0.4

The above table excludes 75 gross (28 net) wells drilled or acquired by CCBM through 2002. At December 31, 2002, we have ownership in 11 gross (2.7 net) wells with dual completion in single bore holes.

PRODUCTIVE WELLS

The following table sets forth the number of productive natural gas and oil wells in which we owned an interest as of December 31, 2002.

	COMPANY OPERATED		OTHER		TOTAL	
	GROSS	NET	GROSS	NET	GROSS	NET
Oil	49	46	18	6	67	52
Natural Gas	36	19	59	15	95	34
Total	85	65	77	21	162	86

ACREAGE DATA

The following table sets forth certain information regarding our developed and undeveloped lease acreage as of September 30, 2003. Developed acres refers to acreage within producing units and undeveloped acres refers to acreage that has not been placed in producing units. Leases covering substantially all of the undeveloped acreage in the following table will expire within the next three years. In general, our leases will continue past their primary terms if natural gas or oil in commercial quantities is being produced from a well on such leases.

	DEVELOPED ACREAGE		UNDEVELOPED ACREAGE		TOTAL	
	GROSS	NET	GROSS	NET	GROSS	NET
Onshore Gulf Coast..........	40,449	14,767	44,182	18,675	84,631	33,44
East Texas...................	360	220	687	342	1,047	56
Rocky Mountain..............	--	--	145,376	16,710	145,376	16,71
U.K. North Sea..............	--	--	209,613	209,613	209,613	209,61
Total......................	40,809	14,987	399,858	245,340	440,667	260,32

The table does not include 7,422 gross acres (3,334 net) that we had a right to acquire in Texas pursuant to various seismic options or agreements at September 30, 2003. 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 28,511 gross and 10,403 net acres in Wyoming that we have the right to earn pursuant to specified drilling obligations and other predetermined terms.

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. 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:

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

See "Risk Factors--Natural gas and oil prices are highly volatile, and lower prices will negatively affect our financial results," "Risk Factors--We are subject to various governmental regulations and environmental risks" and "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" and "Management's Discussion and Analysis of Financial Condition and Results of Operations--Qualitative and Quantitative Disclosures About Market Risk--Derivative Instruments and Hedging Activities."

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. See "Management's Discussion and Analysis of Financial Condition and Results of Operations," "Risk Factors--We face strong competition from larger natural gas and oil companies" and "Risk Factors--We have substantial capital requirements that, if not met, may hinder operations."

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. See "Management's Discussion and Analysis of Financial Condition and Results of Operations," "Risk Factors--We may not be able to keep pace with technological developments in our industry," "Risk Factors--We may experience difficulty in achieving and managing future growth" and "Risk Factors--We have substantial capital requirements that, if not met, may hinder operations."

REGULATION

Natural gas and oil operations are subject to various federal, state and local 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 allow the forced pooling or integration of tracts to facilitate exploration while other states rely primarily or exclusively on voluntary pooling of lands and leases. In areas where pooling is voluntary, it may be more difficult to form units and therefore more difficult to develop a project if the operator owns less than 100% of the leasehold. In addition, state conservation laws 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 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. 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. These regulations generally have been approved on judicial review. 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. The first such review was completed in 2000 and on December 14, 2000, the

FERC reaffirmed the current index. Following a successful court challenge of these orders by an association of oil pipelines, on February 24, 2003 the FERC increased the index slightly for the current five-year period, effective July 2001. 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. 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 wastes 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 wastes. Furthermore, certain wastes generated by our natural gas and oil operations that are currently exempt from treatment as "hazardous wastes" may in the future be designated as "hazardous wastes" 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 wastes may have been disposed of or released on or under the properties we own or lease or on or under locations where such wastes 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 wastes was not under our control. These properties and the wastes 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 wastes. Under these laws, we could be required to remove or remediate previously disposed wastes (including wastes disposed of or released by prior owners or operators) or property contamination (including groundwater contamination) or to perform remedial plugging operations to prevent future contamination. See "Risk Factors--We are subject to various governmental regulations and environmental risks."

CERCLA, also known as the "Superfund" law, and similar state laws impose liability, without regard to fault or the legality of the original conduct, on specified classes of persons that are considered to have contributed to the release of a "hazardous substance" into the environment. These classes of persons include the owner or operator of the disposal site or sites where the release occurred and companies that disposed or arranged for the disposal of the hazardous substances found at the site. Persons who are or were responsible for releases of hazardous substances under CERCLA may be subject to joint and several liability for the costs of cleaning up the hazardous substances that have been released into the environment, for damages to natural resources and for the costs of certain health studies, and it is not uncommon for neighboring landowners and other third parties to file claims for personal injury and property damage allegedly caused by the hazardous substances released into the environment.

Our operations may be subject to the Clean Air Act (CAA) and comparable state and local requirements. In 1990 Congress adopted amendments to the CAA containing provisions that have resulted in the gradual imposition of certain pollution control requirements with respect to air emissions from our operations. The EPA and states have developed and continue to develop regulations to implement these requirements. We may be required to incur certain capital expenditures in the next several years for air pollution control equipment in connection with maintaining or obtaining operating permits and approvals addressing other air emission-related issues. However, we do not believe our operations will be materially adversely affected by any such requirements.

Federal regulations require certain owners or operators of facilities that store or otherwise handle oil, such as us, to prepare and implement spill prevention, control, countermeasure (SPCC) and response plans relating to the possible discharge of oil into surface waters. We have acknowledged the need for SPCC plans at certain of our properties and have developed and implemented these plans. 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, participate in a group permit or seek coverage under an EPA general permit. While certain of our properties may require permits for discharges of storm water runoff, we believe that we will be able to obtain, or be included under, such permits, where necessary, and make minor modifications to existing facilities and operations that would not have a material effect on us. 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.

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

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. See "Risk Factors--We are subject to various governmental regulations and environmental risks."

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. See "Risk Factors--We may not have enough insurance to cover all of the risks we face."

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. See "Risk Factors--We cannot control the activities on properties we do not operate and are unable to ensure their proper operation and profitability."

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 "Risk Factors -- Our future acquisitions may yield revenues or production that varies significantly from our projections."

EMPLOYEES

At September 30, 2003, we had 37 full-time employees, including six geoscientists and six 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. See "Risk Factors--Our business may suffer if we lose key personnel."

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 received 37.5% of the common stock of Pinnacle and options to purchase additional Pinnacle common stock. We retained our interests in approximately 189,000 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.

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. The CSFB parties also agreed to contribute additional cash, under specified circumstances, of up to approximately $11.8 million to Pinnacle to fund future drilling, development and acquisitions. The CSFB parties currently have greater than 50% of the voting power of the Pinnacle capital stock through their ownership of Pinnacle common and preferred stock.

Currently, on a fully diluted basis, assuming that all parties exercised their Pinnacle warrants and options, the CSFB parties would have an ownership interest in Pinnacle of 46.2%, and we and RMG each would own 26.9%. On a fully diluted basis, assuming the additional $11.8 million of cash were contributed by the CSFB parties and all warrants and options were exercised by all parties, the CSFB parties would own 54.6% of Pinnacle and RMG and we each would own 22.7% of Pinnacle.

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. The leases include 95 producing coalbed methane wells currently in the early stages of dewatering, a process that occurs prior to achieving stabilized production. At the time of the Pinnacle transaction, these wells were producing at a combined gross rate of approximately 2.5 MMcfd, or an estimated 1 MMcfd net to Pinnacle. Pinnacle also agreed to fund up to $14.9 million of future drilling and development costs on these properties on behalf of the third party prior to December 31, 2005. The drilling and development work will be done under the terms of an earn-in joint venture agreement between Pinnacle and Gastar. As of September 30, 2003, Pinnacle owned interests in approximately 131,000 gross acres in the Powder River Basin.

Certain Relationships and Agreements

Our Chairman, Steven A. Webster, is also Chairman of Global Energy Partners, Ltd., an affiliate of CSFB Private Equity and could be deemed a related party with respect to the Pinnacle transaction.

We provide specified accounting, treasury, tax, insurance and financial reporting functions to Pinnacle through the end of 2003 under a transition services agreement for a monthly fee equal to our actual cost to provide these services. After December 31, 2003, the agreement will automatically renew on a quarterly basis unless one of the parties gives notice of its intent to terminate the agreement.

We have mutually agreed with RMG, its majority shareholder and the CSFB parties to provide Pinnacle the right until June 23, 2008 to acquire at cost any interest in natural gas and oil leases or mineral interests in the Powder River Basin in Wyoming and Montana, but excluding most of Powder River County, Montana, that such parties may have acquired in the covered area, subject to specified exceptions.

We, the CSFB parties, RMG, RMG's parent company, Peter G. Schoonmaker, Gary W. Uhland and Pinnacle also entered into a securityholders' agreement providing for an initial eight person board of directors, which initially includes four directors nominated by the CSFB parties and two nominated by each of us and RMG, subject to change as their respective ownership percentages change. Each party to the securityholders' agreement also granted to the others a right of first offer and co-sale rights. If the CSFB parties propose to sell all of their Pinnacle shares to a third party, under specified circumstances the CSFB parties may require the other securityholders to include all of their Pinnacle shares in that sale. In event of such a sale, the Pinnacle preferred stock will have a preferred right to receive an amount equal to its liquidation value (as defined below) per share plus accrued and unpaid dividends prior to distributions to the holders of shares of Pinnacle common stock and common stock equivalents. Pinnacle also granted the securityholders pre-emptive rights to purchase additional securities in order to maintain their proportionate ownership of Pinnacle. The securityholders' agreement also provides generally for multiple demand registration rights with respect to the Pinnacle common stock in favor of the CSFB parties and certain piggyback registration rights for us and RMG subject to the satisfaction of specified conditions.

Pinnacle Preferred Stock and Warrants Held by the CSFB Parties

The Pinnacle redeemable preferred stock issued to the CSFB parties generally has the right to vote together with the Pinnacle common stock and has a class vote on specified matters, including specified extraordinary transactions. In the event of any dissolution, liquidation, or winding up by Pinnacle, the holder of each share of Pinnacle preferred stock will be entitled to be paid a liquidation value of $100 per share out of the assets of Pinnacle available for distribution to its shareholders.

Dividends on the Pinnacle preferred stock are payable either in cash at a rate of 10.5% per annum through June 23, 2011 and 12.5% thereafter or, at Pinnacle's option, by payment in kind of additional shares of the Pinnacle preferred stock. For each additional share of Pinnacle preferred stock distributed to a holder as an in-kind dividend, Pinnacle will also deliver to that holder one Pinnacle warrant, which will have an exercise price equal to the exercise price of the outstanding Pinnacle warrants on the date of such distribution. On or after July 1, 2005, Pinnacle may redeem all or any portion of the Pinnacle preferred stock, provided that if any Pinnacle warrants are still outstanding, Pinnacle may redeem all but a single share; if the redemption occurs at any time before July 1, 2009, the redemption price will be at a premium to the liquidation value of the shares.

Pinnacle is required to redeem its preferred stock upon:

- specified changes of control, at a price per share equal to 101% of its liquidation value; or

- specified events of default, at a price per share equal to 110% of the liquidation value prior to June 30, 2005 and, thereafter, equal to an optional redemption price that decreases over time.

The Pinnacle warrants entitle the holders to purchase up to 130,000 shares of Pinnacle common stock at a price of $100 per share and are exercisable at any time until June 30, 2013. The Pinnacle warrants can be exercised in cash, by tender of the Pinnacle preferred stock and on a cashless net exercise basis. The Pinnacle warrants are subject to adjustments, including, in specified cases, an adjustment of the exercise price to equal the lowest price at which Pinnacle common stock is sold if such shares are sold below the then-current exercise price.

MANAGEMENT

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

NAME	AGE	POSITION
S.P. Johnson IV........................	47	President, Chief Executive Officer and Director
Paul F. Boling.........................	49	Chief Financial Officer, Vice President, Secretary and Treasurer
Jeremy T. Greene.......................	43	Vice President of Exploration
Kendall A. Trahan......................	53	Vice President of Land
J. Bradley Fisher......................	42	Vice President of Operations
Steven A. Webster......................	52	Chairman
Christopher C. Behrens.................	42	Director
Douglas A. P. Hamilton.................	57	Director
Paul B. Loyd, Jr.	57	Director
Bryan R. Martin........................	36	Director
F. Gardner Parker......................	61	Director
Frank A. Wojtek........................	48	Director

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

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.

Jeremy T. Greene was elected Vice President of Exploration in August 2002. From September 2000 to August 2002 he was the Deepwater Gulf of Mexico Division Specialist for EOG Resources, Inc. Mr. Greene was the Eastern Area Deepwater Exploration Manager for Vastar Resources, Inc. from August 1997 to September 2000. He spent the previous 14 years with Vastar Resources, Inc., ARCO International and ARCO, where he held various technical and managerial positions, including Director of Joint Ventures Onshore Gulf Coast and Director of Geophysical Interpretation Research. Mr. Greene received his B.S. in Geophysical Engineering from the Colorado School of Mines and his M.S. in Geophysics from The University of Texas at Austin.

Kendall A. Trahan has been head of our land activities since joining us in March 1997 and was elected Vice President of Land in June 1997. From 1994 to February

1997, he served as a Director of Joint Ventures Onshore Gulf Coast for Vastar Resources, Inc. From 1982 to 1994, he worked as an Area Landman and then a Division Landman and Director of Business Development for Arco Oil & Gas Company. Prior to that, Mr. Trahan served as a Staff Landman for Amerada Hess Corporation and as an independent Landman. He holds a B.S. degree from the University of Southwestern Louisiana.

J. Bradley Fisher has 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 hold a B.S. degree in Petroleum Engineering from Texas A&M University.

Steven A. Webster has been the Chairman of our Board of Directors since June 1997 and has been a director since 1993. Mr. Webster serves as the Chairman of Global Energy Partners, Ltd., an affiliate of CSFB Private Equity, which makes private equity investments in the energy business. From December 1997 to May 1999, Mr. Webster was the Chief Executive Officer and President of R&B Falcon Corporation, an offshore drilling contractor, and prior to that, was Chairman and Chief Executive Officer of Falcon Drilling Company, which he founded in 1988. Mr. Webster is also a director of Grey Wolf, Inc. (an onshore drilling company), Seabulk International, Inc. (a marine transportation and service provider), Geokinetics, Inc. (a seismic acquisition and geophysical services company), Crown Resources Corporation (a precious metals exploration company), Goodrich Petroleum Corporation (an oil and gas exploration company), Basic Energy Services, Inc. (a well servicing company) and Brigham Exploration Company (an oil and gas exploration company), as well as various private companies. He is also a trust manager of Camden Property Trust (a real estate investment trust). Mr. Webster holds an M.B.A. degree from Harvard Business School and a Bachelor of Science in Industrial Management degree from Purdue University.

Christopher C. Behrens has been a director since December 1999. Since 1998, Mr. Behrens has been a General Partner of J.P. Morgan Partners, LLC (formerly Chase Capital Partners), the private equity investment affiliate of JP Morgan Chase & Co. which focuses on energy investments and industrial buyouts. Mr. Behrens is a director of Brand Services Inc., Interline Brands, Inc. and Berry Plastics Corporation, as well as various private companies. Mr. Behrens received a B.A. from the University of California at Berkeley and an M.A. from Columbia University.

Douglas A. P. Hamilton has been a director since 1993. Mr. Hamilton, a private investor, has been an active investor in the oil and gas business since 1985. Mr. Hamilton has been the President of Anatar Investments, Inc., a diversified investment capital firm with active investments in oil and gas and offshore contract drilling, since 1979 and is a co-owner of the French Culinary Institute, a cooking school in New York City. Mr. Hamilton has a degree from the University of North Carolina and completed the Program for Management Development at Harvard Business School.

Paul B. Loyd, Jr., has been a director since 1993. Mr. Loyd was Chairman of the Board and Chief Executive Officer of Reading & Bates Corporation from 1991 to 1997 and from 1999 to 2001 until its merger with Transocean Inc. Mr. Loyd has been the principal of Loyd & Associates, Inc., a private financial consulting firm, since 1989. Mr. Loyd was Chief Executive Officer and a director of Chiles-Alexander International, Inc. from 1987 to 1989, President and a director of

Griffin-Alexander Drilling Company, from 1984 to 1987, and prior to that, a director and Chief Financial Officer of Houston Offshore International, all of which are companies in the offshore drilling industry. Mr. Loyd is currently a director of Transocean Inc. (an offshore drilling contractor) and Frontier Oil Corporation (a refining and marketing company) and is a member of the Board of Trustees of Southern Methodist University. Mr. Loyd served as President of our company from its inception in September 1993 until December 1993. Mr. Loyd holds an undergraduate degree from Southern Methodist University and an M.B.A. degree from Harvard Business School.

Bryan R. Martin has been a director since March 2002. Since 2000, he has been a Principal at J.P. Morgan Partners, LLC (formerly Chase Capital Partners), the private equity investment affiliate of JP Morgan Chase & Co. which focuses on energy investments and industrial buyouts. Prior to his role at J.P. Morgan Partners, LLC, Mr. Martin was a Partner of the Beacon Group since 1994 and co-manager of the Beacon Group Energy Funds. Prior to that Mr. Martin worked as an Equity Analyst at Fidelity Investments co-managing the Select Energy and Specialty Retail portfolios. Mr. Martin holds a bachelors degree from Yale University and a Masters in Management from the J. L. Kellogg Graduate School of Management. Mr. Martin is also a director of Coherent Networks, Crosstown Traders, SmartSynch, Shell Technology Investment Partners and Wellogix. In addition, Mr. Martin is a member of the Investment Committees of Lime Rock Partners and Shell Technology Investment Partners.

F. Gardner Parker has been a director since 2000. He has been Managing Outside Trust Manager with Camden Property Trust since 1998. He also serves on the boards of Crown Resources Corporation and Sharps Compliance Corp. (a waste management services provider). In addition, he serves on the board of directors of the following private companies: Gillman Automobile Dealerships, Net Near U Communications, MCS Technologies, Camp Longhorn, Inc., nii communications, inc., Sherwood Healthcare Inc., and Arena Power. Mr. Parker also worked with Ernst & Ernst (now Ernst & Young LLP) for 14 years, seven of which he served as a partner. He is a graduate of The University of Texas.

Frank A. Wojtek has been a director since 1993. Mr. Wojtek served as our Chief Financial Officer, Vice President, Secretary and Treasurer from 1993 until August 2003. From 1992 to 1997, Mr. Wojtek was the Assistant to the Chairman of the Board of Reading & Bates Corporation (an offshore drilling company). Mr. Wojtek has also held the positions of Vice President and Secretary/Treasurer of Loyd & Associates, Inc., a private financial consulting firm, since 1989. Mr. Wojtek held the positions of Vice President and Chief Financial Officer of Griffin-Alexander Drilling Company from 1984 to 1987, Treasurer of Chiles-Alexander International Inc. from 1987 to 1989, and Vice President and Chief Financial Officer of India Offshore Inc. from 1989 to 1992, all of which were companies in the offshore drilling industry. Mr. Wojtek is a Certified Public Accountant and holds a B.B.A. in Accounting with Honors from The University of Texas.

DESCRIPTION OF CAPITAL STOCK

The description of our capital stock in this section is a summary and is not intended to be complete. For a complete description of our capital stock, please read our amended and restated articles of incorporation and our amended and restated bylaws, the Statement of Resolution relating to our Series B preferred stock and the warrant agreements setting forth the terms of our outstanding warrants, all of which have been filed with the SEC.

GENERAL

Our authorized capital stock consists of (1) 40,000,000 shares of common stock, par value $0.01 per share, and (2) 10,000,000 shares of preferred stock, par value $0.01 per share. Immediately following this offering, excluding shares that may be sold upon exercise of the underwriters' over-allotment option, approximately 18,010,015 shares of common stock and 68,559 shares of preferred stock will be outstanding.

COMMON STOCK

The holders of our common stock are entitled to one vote per share on all matters on which shareholders are permitted to vote. The holders of our common stock have no preemptive rights to purchase or subscribe for our securities, and our common stock is not convertible or subject to redemption by us.

Subject to the rights of the holders of any class of our capital stock having any preference or priority over our common stock, the holders of our common stock are entitled to dividends in such amounts as may be declared by our board of directors from time to time out of funds legally available for such payments and, if we are liquidated, dissolved or wound up, to a ratable share of any distribution to shareholders, after satisfaction of all our liabilities and the prior rights of any outstanding class of our preferred stock.

Computershare Trust Company, Inc. is the registrar and transfer agent for our common stock.

PREFERRED STOCK

Our board of directors has the authority, without shareholder approval, to issue shares of preferred stock in one or more series, and to fix the number and terms of each such series. We have no present plan to issue additional shares of preferred stock.

The issuance of shares of preferred stock could adversely affect the voting power of holders of our common stock, discourage an unsolicited acquisition proposal or make it more difficult for a third party to gain control of our company. For instance, the issuance of a series of preferred stock might impede a business combination by including class voting rights that would enable the holder to block such a transaction or facilitate a business combination by including voting rights that would provide a required percentage vote of the shareholders. Although our board of directors is required to make any determination to issue preferred stock based on its judgment as to the best interests of our shareholders, the board could act in a manner that would discourage an acquisition attempt or other transaction that some of the shareholders might believe to be in their best interests or in which shareholders might receive a premium for their stock over the then market price of the stock. Our board of directors does not presently intend to seek shareholder approval prior to any issuance of currently authorized stock unless otherwise required by law or the rules of the Nasdaq National Market.

Series B Preferred Stock

In February 2002 we adopted a Statement of Resolution establishing a series of

150,000 shares of our preferred stock, designated as Series B Convertible Participating Preferred Stock, and issued 60,000 shares of our Series B preferred stock to Mellon and Steven A. Webster. We had 68,559 shares of our Series B preferred stock outstanding as of September 30, 2003.

The affirmative vote or written consent of a majority of the holders of our Series B preferred stock, voting as a class, is required for us to:

- create, authorize or issue, or effect any corporate transaction that results in the creation or issuance of, any class or series of our equity securities that rank senior to the Series B preferred stock or on parity with the Series B preferred stock as to payment of dividends or distributions upon our liquidation, dissolution or winding up;

- effect any corporate transaction or approve an amendment to our articles of incorporation that would result in a change in the aggregate number of authorized shares of Series B preferred stock or a change in the designations, preferences, limitations or relative rights of the shares of Series B preferred stock;

- effect any change in our articles of incorporation or bylaws that adversely affects the rights, preferences or privileges of the Series B preferred stock;

- materially change the nature of our business; or

- issue any shares of Series B preferred stock except pursuant to the securities purchase agreement under which we issued the 60,000 shares described above.

The holders of our Series B preferred stock are not permitted to vote on any other matters except as required by applicable law. For any matter on which the holders of our Series B preferred stock are permitted to vote, each such holder is entitled to one vote per share, and the affirmative vote of the holders of a majority of the outstanding shares of Series B preferred shares entitled to vote is required to approve the matter.

The holders may convert the Series B preferred stock into common stock at a conversion price of $5.70 per share, subject to adjustment for transactions including issuance of common stock or securities convertible into or exercisable for common stock at less than the conversion price of the Series B preferred stock.

Dividends on our Series B preferred stock are payable in either cash at a rate of 8% per annum or, at our option, by payment in kind of additional shares of the Series B preferred stock at a rate of 10% per annum. At December 31, 2002 and September 30, 2003, the outstanding balance of the Series B preferred stock has been increased by $0.5 million (5,294 shares) and $0.9 million (8,559 shares), respectively, for dividends paid in kind. At September 30, 2003, we had accrued a dividend of $0.2 million that is payable on December 31, 2003. In addition to the foregoing, if we declare a cash dividend on our common stock, the holders of shares of Series B preferred stock are entitled to receive for each share of Series B preferred stock a cash dividend in the amount of the cash dividend that would be received by a holder of the common stock into which that share of Series B preferred stock is convertible on the record date for the cash dividend. Unless all accrued dividends on the Series B preferred stock shall have been paid and a sum sufficient for the payment thereof set apart, no distributions may be paid on any Junior Stock (as defined in the Statement of

Resolutions for the Series B preferred stock) (which includes the common stock) and no redemption of any Junior Stock shall occur other than subject to certain exceptions.

We must redeem the Series B preferred stock at any time after the third anniversary of its initial issuance upon request from any holder at a price per share equal to Purchase Price/Dividend Preference (as defined below). We may redeem the Series B preferred stock after the third anniversary of its initial issuance at a price per share equal to the Purchase Price/Dividend Preference and, prior to that time, at varying preferences to the Purchase Price/Dividend Preference. "Purchase Price/Dividend Purchase" is defined to mean, generally, $100 plus all cumulative and accrued dividends on that share of Series B preferred stock.

In the event of any dissolution, liquidation or winding up or certain mergers or sales or other disposition by us of all or substantially all of our assets, the holder of each share of Series B preferred stock then outstanding will be entitled to be paid per share of Series B preferred stock, prior to payment to holders of our common stock and out of our assets available for distribution to our shareholders, the greater of:

- $100 in cash plus all cumulative and accrued dividends; and

- in specified circumstances, the "as-converted" liquidation distribution, if any, payable in such liquidation with respect to each share of common stock.

Upon the occurrence of specified events constituting a "Change of Control" (as defined in the Statement of Resolutions), we must make an offer to each holder of Series B preferred stock to repurchase all of that holder's Series B preferred stock at an offer price per share of Series B preferred stock in cash equal to 105% of the Change of Control Purchase Price, which is generally defined to mean $100 plus all cumulative and accrued dividends.

WARRANTS

We have outstanding warrants expiring in February 2007 to purchase up to 252,632 shares of our common stock at a price of $5.94 per share, subject to adjustment. We sold these warrants to Mellon and Steven A. Webster in connection with our issuance to them of Series B preferred stock. These warrants are exercisable at any time after issuance and are valued for accounting purposes at $0.06 per warrant.

We have outstanding warrants expiring in December 2007 to purchase up to 2,760,189 shares of our common stock at an exercise price of $2.20 per share, subject to adjustment. We sold these warrants in December 1999 to JPMorgan, Mellon, Paul B. Loyd, Jr., Steven A. Webster and Douglas A.P. Hamilton in connection with the sale of $22.0 million principal amount of 9% Senior Subordinated Notes due 2007. These warrants are exercisable at any time after issuance and are valued for accounting purposes at $0.25 each.

We have outstanding warrants expiring in January 2005 to purchase up to 250,000 shares of our common stock at an exercise price of $4.00 per share, subject to adjustment. We initially sold 1,000,000 warrants in January 1998 to certain parties associated with Enron Corp. at an exercise price of $11.50 per share. In connection with the 1999 transaction described in the preceding paragraph, we repurchased 750,000 of those warrants and reduced the exercise price on the remaining outstanding warrants to $4 per share.

SPECIAL MEETINGS

Our articles of incorporation provide that special meetings of our shareholders may be called only by the chairman of our board of directors, our president, a majority of our board of directors or by shareholders holding not less than 50% of our outstanding voting stock.

VOTING

Our common stock does not have cumulative voting rights. Accordingly, holders of a majority of the total votes entitled to vote in an election of directors will be able to elect all of the directors. See "Risk Factors--Certain of our affiliates control a majority of our outstanding common stock, which may affect your vote as a shareholder."

Our articles of incorporation or Texas law requires the affirmative vote of holders of:

- 66 2/3% of the outstanding shares entitled to vote on the matter to approve any merger, consolidation or share exchange, any disposition of our assets or any dissolution of our company; and

- a majority of the outstanding shares entitled to vote on the matter to approve any amendment to our articles of incorporation or any other matter for which a shareholder vote is required by the Texas Business Corporation Act. If any class or series of shares is entitled to vote as a class with regard to these events, the vote required will be the affirmative vote of the holders of a majority of the outstanding shares within each class or series of shares entitled to vote thereon as a class and at least a majority of the outstanding shares of capital stock otherwise entitled to vote thereon.

Our bylaws provide that shareholders who wish to nominate directors or to bring business before a shareholders' meeting must notify us and provide pertinent information at least 80 days before the meeting date, or within 10 days after public announcement pursuant to our bylaws of the meeting date, if the meeting date has not been publicly announced at least 90 days in advance.

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Our articles of incorporation and bylaws provide that no director may be removed from office except for cause and upon the affirmative vote of the holders of a majority of the votes entitled to be cast in the election of our directors. The following events constitute "cause":

- the director has been convicted, or is granted immunity to testify where another has been convicted, of a felony;

- the director has been found by a court or by the affirmative vote of a majority of all other directors to be grossly negligent or guilty of willful misconduct in the performance of duties to us;

- the director is adjudicated mentally incompetent; or

- the director has been found by a court or by the affirmative vote of a majority of all other directors to have breached his duty of loyalty to us or our shareholders or to have engaged in a transaction with us from which the director derived an improper personal benefit.

BUSINESS COMBINATION LAW

We are subject to Part Thirteen (the "Business Corporation Law") of the Texas Business Corporation Act. In general, the Business Combination Law prevents an "affiliated shareholder" or its affiliates or associates from entering into or engaging in a "business combination" with an "issuing public corporation" during the three-year period immediately following the affiliated shareholder's acquisition of shares unless:

- before the date the person became an affiliated shareholder, the board of directors of the issuing public corporation approved the business combination or the acquisition of shares made by the affiliated shareholder on that date; or

- not less than six months after the date the person became an affiliated shareholder, the business combination is approved by the affirmative vote of holders of at least two-thirds of the issuing public corporation's outstanding voting shares not beneficially owned by the affiliated shareholder or its affiliates or associates.

For the purposes of the Business Combination Law, an "affiliated shareholder" is defined generally as a person who is or was within the preceding three-year period the beneficial owner of 20% or more of a corporation's outstanding voting shares. A "business combination" is defined generally to include:

- mergers or share exchanges;

- dispositions of assets having an aggregate value equal to 10% or more of the market value of the assets or of the outstanding common stock representing 10% or more of the earning power or net income of the corporation;

- certain issuances or transaction by the corporation that would increase the affiliated shareholder's number of shares of the corporation;

- certain liquidations or dissolutions; and

- the receipt of tax, guarantee, loan or other financial benefits by an affiliated shareholder of the corporation.

An "issuing public corporation" is defined generally as a Texas corporation with 100 or more shareholders, any voting shares registered under the Securities Exchange Act of 1934 or any voting shares qualified for trading in a national market system.

The Business Combination Law does not apply to a business combination of an issuing public corporation that elects not be governed thereby through either its original articles of incorporation or bylaws or by an amendment thereof. Our articles of incorporation and bylaws do not so provide, nor do we currently intend to make any such amendments.

As a result of the approval of the Board of Directors of the acquisition of shares by our original shareholders, none of Steven A. Webster, Douglas A. P. Hamilton, Paul B. Loyd, Jr. or Frank A. Wojtek (those shareholders of our company owning 20% or more of the outstanding voting shares prior to our initial public offering) will be subject to the restrictions imposed on affiliated shareholders by the Business

Combination Law, nor is JPMorgan, Mellon or the parties subject to current shareholder agreements with these entities subject to such restrictions as a result of either their current investments in our company or those shareholder agreements.

In discharging the duties of a director under Texas law, a director, in considering the best interests of our company, may consider the long-term as well as the short-term interests of our company and our shareholders, including the possibility that those interests may be best served by our continued independence.

LIMITATION OF DIRECTOR LIABILITY AND INDEMNIFICATION ARRANGEMENTS

Our articles of incorporation contain a provision that limits the liability of our directors as permitted by the Texas Business Corporation Act. The provision eliminates the personal liability of a director to us and our shareholders for monetary damages for an act or omission in the director's capacity as a director. The provision does not change the liability of a director for breach of his duty of loyalty to us or to our shareholders, for an act or omission not in good faith that involves intentional misconduct or a knowing violation of law, for an act or omission for which the liability of a director is expressly provided for by an applicable statute, or in respect of any transaction from which a director received an improper personal benefit. Pursuant to our articles of incorporation, the liability of directors will be further limited or eliminated without action by shareholders if Texas law is amended to further limit or eliminate the personal liability of directors.

Our bylaws provide for the indemnification of our officers and directors, and the advancement to them of expenses in connection with proceedings and claims, to the fullest extent permitted by the Texas Business Corporation Act. We have also entered into indemnification agreements with each of our directors and some of our officers that contractually provide for indemnification and expense advancement and include related provisions meant to facilitate the indemnitee's receipt of such benefits. In addition, we may purchase directors', and officers' liability insurance policies for our directors and officers in the future. Our bylaws and these agreements with directors and officers provide for indemnification for amounts:

- in respect of the deductibles for these insurance policies;

- that exceed the liability limits of our insurance policies; and

- that are available, were available or become available to us or are generally available to companies comparable to us but which our officers or directors determine is inadvisable for us to purchase, given the cost.

Such indemnification may be made even though our directors and officer would not otherwise be entitled to indemnification under other provisions of our bylaws or these agreements.

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UNDERWRITING

We and the selling shareholders have entered into an underwriting agreement with the underwriters named below. CIBC World Markets Corp., First Albany Capital Inc., Hibernia Southcoast Capital, Inc. and Johnson Rice & Company L.L.C. are acting as representatives of the underwriters.

The underwriting agreement provides for the purchase of a specific number of shares of common stock by each of the underwriters. The underwriters' obligations are several, which means that each underwriter is required to purchase a specified number of shares, but is not responsible for the commitment of any other underwriter to purchase shares. Subject to the terms and conditions of the underwriting agreement, each underwriter has severally agreed to purchase the number of shares of common stock set forth opposite its name below:

UNDERWRITER	NUMBER OF SHARES
CIBC World Markets Corp....................................	
First Albany Capital Inc...................................	
Hibernia Southcoast Capital, Inc.	
Johnson Rice & Company L.L.C.	
Total...	5,700,000

The underwriters have agreed to purchase all of the shares offered by this prospectus (other than those covered by the over-allotment option described below) if any are purchased. Under the underwriting agreement, if an underwriter defaults in its commitment to purchase shares, the commitments of nondefaulting underwriters may be increased or the underwriting agreement may be terminated, depending on the circumstances.

The shares should be ready for delivery on or about , 2004, against payment in immediately available funds. The underwriters are offering the shares subject to various conditions and may reject all or part of any order. The representatives have advised us and the selling shareholders that the underwriters propose to offer the shares directly to the public at the public offering price that appears on the cover page of this prospectus. In addition, the representatives may offer some of the shares to other securities dealers at such price less a concession of $ per share. The underwriters may also allow, and such dealers may reallow, a concession not in excess of $ per share to other dealers. After the shares are released for sale to the public the representatives may change the offering price and other selling terms at various times.

We and some of the selling shareholders have granted the underwriters an over-allotment option, exercisable for up to 30 days after the date of this prospectus, which permits the underwriters to purchase a maximum of 855,000 additional shares (256,500 from us and 598,500 from the selling shareholders) to cover over-allotments. If the underwriters exercise all or part of this option, they will purchase shares covered by the option at the public offering price that appears on the cover page of this prospectus, less the underwriting discount. If this option is exercised in full, the total price to the public will be $. The total proceeds to us will be $ and the total proceeds to the selling shareholders will be $. The underwriters have severally agreed that, to the extent the over-allotment option is exercised, they will each purchase a number of additional shares proportionate to the underwriter's initial amount reflected in the foregoing table.

The following table provides information regarding the amount of the discount to be paid to the underwriters by us and the selling shareholders:

	PER SHARE	TOTAL WITHOUT EXERCISE OF OVER-ALLOTMENT OPTION	TOTAL WITH EXERCISE OF OVER-ALLOTMENT O
Carrizo Oil & Gas, Inc.	$	$	$
Selling Shareholders			
Total			

We estimate that the total expenses of the offering, excluding the underwriting discount, will be approximately $.

We and the selling shareholders have agreed to indemnify the underwriters against certain liabilities, including liabilities under the Securities Act of 1933.

We, our officers and directors and the selling shareholders have agreed to a 90-day "lock up" with respect to all of the shares of common stock that they beneficially own, including securities that are convertible into shares of common stock and securities that are exchangeable or exercisable for shares of common stock. This means that, subject to certain exceptions, for a period of 90 days following the date of this prospectus, we and such persons may not offer, sell, pledge or otherwise dispose of these securities without the prior written consent of CIBC World Markets Corp.

Other than in the United States, no action has been taken by us, the selling shareholders or the underwriters that would permit a public offering of the shares of common stock offered by this prospectus in any jurisdiction where action for that purpose is required. The shares of common stock offered by this prospectus may not be offered or sold, directly or indirectly, nor may this prospectus or any other offering material or advertisements in connection with the offer and sale of any such shares of common stock be distributed or published in any jurisdiction, except under circumstances that will result in compliance with the applicable rules and regulations of that jurisdiction. Persons into whose possession this prospectus comes are advised to inform themselves about, and to observe any restrictions relating to the offering and the distribution of this prospectus. This prospectus does not constitute an offer to sell or a solicitation of an offer to buy any shares of common stock offered by this prospectus in any jurisdiction in which such an offer or a solicitation is unlawful.

Our common stock is traded on the Nasdaq National Market under the symbol "CRZO."

Hibernia National Bank, the lender under our credit facility, is an affiliate of Hibernia Southcoast Capital, Inc. Hibernia National Bank will receive more than 10% of the proceeds of this offering from the sale of primary shares in a temporary repayment of indebtedness under our credit facility. Accordingly, this offering is being made in compliance with the requirements of 2710(c)(8) of the National Association of Securities Dealers, Inc. Conduct Rules.

Rules of the SEC may limit the ability of the underwriters to bid for or purchase shares before the distribution of the shares is completed. However, the underwriters may engage in the following activities in accordance with the rules:

- Stabilizing transactions--The representatives may make bids or purchases for the purpose of pegging, fixing or maintaining the price of the shares, so long as stabilizing bids do not exceed a specified maximum.

- Over-allotments and syndicate covering transactions--The underwriters may sell more shares of common stock in connection with this offering than the number of shares that they have committed to purchase. This over-allotment creates a short position for the underwriters. This short sales position may involve either "covered" short sales or "naked" short sales. Covered short sales are short sales made in an amount not greater than the underwriters' over-allotment option to purchase additional shares in this offering described above. The underwriters may close out any covered short position either by exercising their over-allotment option or by purchasing shares in the open market.

To determine how they will close the covered short position, the underwriters will consider, among other things, the price of shares available for purchase in the open market, as compared to the price at which they may purchase shares through the over-allotment option. Naked short sales are short sales in excess of the over-allotment option. The underwriters must close out any naked short position by purchasing shares in the open market. A naked short position is more likely to be created if the underwriters are concerned that, in the open market after pricing, there may be downward pressure on the price of the shares that could adversely affect investors who purchase shares in this offering.

- Penalty bids--If the representatives purchase shares in the open market in a stabilizing transaction or syndicate covering transaction, they may reclaim a selling concession from the underwriters and selling group members who sold those shares as part of this offering.

- Passive market making--Market makers in the shares who are underwriters or prospective underwriters may make bids for or purchases of shares, subject to limitations, until the time, if ever, at which a stabilizing bid is made.

Similar to other purchase transactions, the underwriters' purchases to cover the syndicate short sales or to stabilize the market price of our common stock may have the effect of raising or maintaining the market price of our common stock or preventing or mitigating a decline in the market price of our common stock. As a result, the price of the shares of our common stock may be higher than the price that might otherwise exist in the open market. The imposition of a penalty bid might also have an effect on the price of the shares if it discourages resale of the shares.

Neither we nor the underwriters make any representation or prediction as to the effect that the transactions described above may have on the price of the shares These transactions may occur on the Nasdaq National Market or otherwise. If such transactions are commenced, they may be discontinued without notice at any time.

The underwriters have an agreement with Yahoo! Net Roadshow to host the roadshow on the internet for qualified investors only, and they will follow the guidance set forth by the staff of the SEC regarding such roadshows. The preliminary prospectus will be posted on the roadshow website for informational purposes only. We do not intend to engage in any other electronic distribution of the prospectus.

LEGAL MATTERS

Certain legal matters in connection with the shares of common stock being offered hereby are being passed upon for us by Baker Botts L.L.P., Houston, Texas. Certain legal matters in connection with this offering are being passed upon for the underwriters by Vinson & Elkins L.L.P., Houston, Texas.

EXPERTS

The consolidated financial statements of Carrizo Oil & Gas, Inc. appearing or incorporated by reference in this prospectus and registration statement have been audited by Ernst & Young LLP, independent auditors, to the extent indicated in their report thereon also appearing elsewhere herein and in the registration statement or incorporated by reference. Such consolidated financial statements have been included herein or incorporated herein by reference in reliance upon such report given on the authority of such firm as experts in accounting and auditing.

The audited financial statements as of December 31, 2000 and 2001 included in this prospectus and elsewhere in the registration statement have been audited by Arthur Andersen LLP, our previous independent public accountants, as indicated in their report with respect thereto, and are included herein in reliance upon the authority of said firm as experts in giving said report. Arthur Andersen LLP completed its audit of our consolidated financial statements at December 31, 2001 and 2000 and for each of the three years in the period ended December 31, 2001 and issued its report with respect to such

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consolidated financial statements on March 20, 2002. On April 11, 2002, we dismissed Arthur Andersen LLP as our independent public accountants.

Your ability to recover for claims against Arthur Andersen LLP may be limited. In particular, you may not be able to effectively recover against Arthur Andersen LLP for any claims you may have under securities or other laws as a result of Arthur Andersen LLP's previous role as our independent public accountants and as author of the audit report for the audited financial statements for the years ended December 31, 2000 and 2001 included in this prospectus.

The letter reports of Ryder Scott Company and Fairchild and Wells, Inc. included as Appendix A to this prospectus and certain information with respect to our natural gas and oil reserves derived therefrom have been included herein in reliance upon such firms as experts with respect to such matters.

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WHERE YOU CAN FIND MORE INFORMATION

We have filed a registration statement on Form S-2 with the SEC in connection with this offering. We file annual, quarterly and current reports, proxy statements and other information with the SEC. You may read and copy the registration statement and any other documents we have filed at the SEC's Public Reference Room at 450 Fifth Street, N.W., Washington, D.C. 20549. Please call the SEC at 1-800-SEC-0330 for further information on the Public Reference Room. Our SEC filings are also available to the public at the SEC's Internet site at http://www.sec.gov.

This prospectus is part of the registration statement and does not contain all of the information included in the registration statement. Whenever a reference is made in this prospectus to any of our contracts or other documents, the reference may not be complete and, for a copy of the contract or document, you should refer to the exhibits that are part of the registration statement.

The SEC allows us to "incorporate by reference" into this prospectus the information we file with it, which means that we can disclose important information to you by referring you to those documents. Information incorporated by reference is part of this prospectus, except for any information that is superseded by information included directly in this prospectus. Later information filed with the SEC will update and supersede this information. We incorporate by reference the documents listed below.

- Our Annual Report on Form 10-K for the year ended December 31, 2002;

- Our Quarterly Report on Form 10-Q for the quarter ended March 31, 2003;

- Item 5 of our Current Report on Form 8-K filed on April 29, 2003;

- Item 5 of our Current Report on Form 8-K filed on May 8, 2003;

- Our Quarterly Report on Form 10-Q for the quarter ended June 30, 2003;

- Item 5 of our Current Report on Form 8-K filed on August 6, 2003;

- Our Quarterly Report on Form 10-Q for the quarter ended September 30, 2003; and

- Item 5 of our Current Report on Form 8-K filed on November 6, 2003.

You may request a copy of these filings, at no cost, by contacting us at:

Carrizo Oil & Gas, Inc.
Attention: Investor Relations
14701 St. Mary's Lane, Suite 800
Houston, Texas 77079
(281) 496-1352

GLOSSARY OF CERTAIN OIL AND GAS TERMS

The definitions set forth below apply to the indicated terms as used in this prospectus. All volumes of natural gas referred to in this prospectus 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.

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.

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.

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 natural gas or oil or, in the case of a dry hole, the reporting of abandonment to the appropriate agency.

Developed acreage. The number of acres that 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 natural gas or oil reserves not classified as proved, to find a new reservoir in a field previously found to be productive of natural gas or oil in another reservoir or to extend a known reservoir.

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 we capitalize 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.

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. Historically prices often have 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.

NYMEX. The New York Mercantile Exchange.

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 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 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 SFAS No. 69 and SEC 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 nonproperty related expenses such as general and administrative expenses, debt service, future income tax expense and depreciation, depletion and amortization, discounted using an annual discount rate of 10%.

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

Reserve Replacement Percentage. Estimated net reserves added to proved reserves through extensions, discoveries and revisions, divided by production for the period.

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 natural gas or oil production free of costs of production.

Standardized Measure. The after-tax 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 and depreciation, depletion and amortization, and discounted using an annual discount rate of 10%.

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.

INDEX TO FINANCIAL STATEMENTS

REPORT OF INDEPENDENT AUDITORS

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

We have audited the accompanying consolidated balance sheet of Carrizo Oil & Gas, Inc. as of December 31, 2002, and the related consolidated statements of operations, shareholders' equity and cash flows for the year then ended. 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 audit. The consolidated financial statements of Carrizo Oil & Gas, Inc. as of December 31, 2001 and for the two years then ended, were audited by other auditors who have ceased operations and whose report dated March 20, 2002, expressed an unqualified opinion on those statements, before the revisions described in Note 5.

We conducted our audit in accordance with auditing standards generally accepted in the 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 audit provides a reasonable basis for our opinion.

In our opinion, the 2002 consolidated financial statements referred to above present fairly, in all material respects, the financial position of the Company as of December 31, 2002, and the results of its operations and its cash flows for the year then ended, in conformity with accounting principles generally accepted in the United States.

As discussed above, the consolidated financial statements of the Company as of December 31, 2001 and for the two years then ended were audited by other auditors who have ceased operations. As described in Note 5, the Company revised the reported amounts of certain temporary differences at December 31, 2001. We audited the adjustments described in Note 5 that were applied to revise the reported amounts of temporary differences in the 2001 consolidated financial statements. Our procedures included (a) agreeing the revised temporary differences to the Company's underlying records obtained from management, and (b) testing the mathematical accuracy of the revisions to the temporary differences. In our opinion, such adjustments are appropriate and have been properly applied. However, we were not engaged to audit, review, or apply any procedures to the 2001 consolidated financial statements of the Company other than with respect to such adjustments and, accordingly, we do not express an opinion or any other form of assurance on the 2001 consolidated financial statements taken as a whole.

ERNST & YOUNG LLP

Houston, Texas
March 14, 2003

THIS IS A COPY OF AN ACCOUNTANTS' REPORT PREVIOUSLY ISSUED BY ARTHUR ANDERSEN LLP. THIS REPORT HAS NOT BEEN REISSUED BY ARTHUR ANDERSEN LLP. AS DESCRIBED IN NOTE 5 TO CARRIZO'S CONSOLIDATED FINANCIAL STATEMENTS AS OF DECEMBER 31, 2002, THE FINANCIAL STATEMENTS FOR THE YEAR ENDED DECEMBER 31, 2001 REFERRED TO IN THIS REPORT HAVE BEEN REVISED SUBSEQUENT TO THE DATE OF THE REPORT TO REFLECT REVISIONS TO TEMPORARY DIFFERENCES IN THE RECOGNITION OF INCOME AND EXPENSES FOR FINANCIAL REPORTING PURPOSES AND FOR TAX PURPOSES. THE REVISIONS HAVE BEEN REPORTED ON BY ERNST & YOUNG LLP.

REPORT OF INDEPENDENT PUBLIC ACCOUNTANTS

To the Shareholders and
Board of Directors of
Carrizo Oil & Gas, Inc.:

We have audited the accompanying consolidated balance sheets of Carrizo Oil & Gas, Inc. (a Texas corporation) as of December 31, 2000 and 2001, and the related consolidated statements of operations, shareholders' equity and cash flows for each of the three years in the period ended December 31, 2001. These consolidated 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 auditing standards generally accepted in the United States. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, the consolidated financial statements referred to above present fairly, in all material respects, the financial position of the Company as of December 31, 2000 and 2001, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2001, in conformity with accounting principles generally accepted in the United States.

As explained in Note 2 to the consolidated financial statements, effective January 1, 2001, the Company changed its method of accounting for derivative instruments and hedging activities to conform with Statement of Financial Accounting Standards No. 133, "Accounting for Derivative Instruments and Hedging Activities". Additionally, as explained in Note 10 to the consolidated financial statements, effective January 1, 1999, the Company changed its method of accounting for start up costs.

ARTHUR ANDERSEN LLP

Houston, Texas
March 20, 2002

CARRIZO OIL & GAS, INC.

CONSOLIDATED BALANCE SHEETS

	AS OF DECEMBER 31, 2001	AS OF DECEMBER 31, 2002
	(in thousands)	
ASSETS		
CURRENT ASSETS:		
Cash and cash equivalents	$ 3,236	$ 4,743
Accounts receivable, trade (net of allowance for doubtful accounts of $0.5 million at December 31, 2001 and 2002, respectively)	8,111	8,207
Advances to operators	509	501
Deposits	48	46
Other current assets	600	605
Total current assets	12,504	14,102
PROPERTY AND EQUIPMENT, net (full-cost method of accounting for oil and natural gas properties)	104,132	120,526
Deferred financing costs	756	760
	$117,392	$135,388
LIABILITIES AND SHAREHOLDERS' EQUITY		
CURRENT LIABILITIES:		
Accounts payable, trade	$ 10,263	$ 9,957
Accrued liabilities	348	1,014
Advances for joint operations	368	1,550
Current maturities of long-term debt	2,107	1,609
Current maturities of seismic obligation payable	-	1,414
Total current liabilities	13,086	15,544
LONG-TERM DEBT	36,081	37,886

SEISMIC OBLIGATION PAYABLE	-	1,103
DEFERRED INCOME TAXES	5,021	7,666
COMMITMENTS AND CONTINGENCIES (Note 9)		
CONVERTIBLE PARTICIPATING PREFERRED STOCK (10,000,000 shares of preferred stock authorized, of which 150,000 are shares designated as convertible participating shares, with 65,294 convertible participating shares issued and outstanding at December 31, 2002)(Note 8)	-	6,373
SHAREHOLDERS' EQUITY:		
Warrants (3,010,189 and 3,262,821 outstanding at December 31, 2001 and 2002, respectively)	765	780
Common stock, par value $.01, (40,000,000 shares authorized with 14,064,077 and 14,177,383 issued and outstanding at December 31, 2001 and 2002, respectively)	141	142
Additional paid in capital	62,736	63,224
Retained earnings (deficit)	(1,144)	3,058
Accumulated other comprehensive income (loss)	706	(388)
	63,204	66,816
	$117,392	$135,388

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

CARRIZO OIL & GAS, INC.

CONSOLIDATED STATEMENTS OF OPERATIONS

	FOR THE YEAR ENDED DECEMBER 31,		
	2000	2001	2002
	(in thousands except for per share amounts)		
OIL AND NATURAL GAS REVENUES	$26,834	$26,226	$26,802
COSTS AND EXPENSES:			
Oil and natural gas operating expenses (exclusive of depreciation shown separately below)	4,941	4,138	4,908
Depreciation, depletion and amortization	7,170	6,492	10,574
General and administrative	3,143	3,333	4,133
Stock option compensation	652	(558)	(84
Total costs and expenses	15,906	13,405	19,531
OPERATING INCOME	10,928	12,821	7,271
OTHER INCOME AND EXPENSES:			
Other income and expenses	1,482	1,777	274
Interest income	592	275	55
Interest expense	(1,459)	(1,040)	(846
Interest expense, related parties	(2,118)	(2,137)	(2,255
Capitalized interest	3,564	3,171	3,100

INCOME BEFORE INCOME TAXES	12,989	14,867	7,599
INCOME TAXES	1,004	5,336	2,809
NET INCOME	$11,985	$ 9,531	$ 4,790
DIVIDENDS AND ACCRETION ON PREFERRED STOCK	-	-	588
NET INCOME AVAILABLE TO COMMON SHAREHOLDERS	$11,985	$ 9,531	$ 4,202
BASIC EARNINGS PER COMMON SHARE	$ 0.85	$ 0.68	$ 0.30
DILUTED EARNINGS PER COMMON SHARE	$ 0.74	$ 0.57	$ 0.26

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

CARRIZO OIL & GAS, INC.

CONSOLIDATED STATEMENTS OF SHAREHOLDERS' EQUITY

	WARRANTS		COMMON STOCK		ADDITIONAL	
	NUMBER	AMOUNT	SHARES	AMOUNT	PAID IN CAPITAL	COMPREHE INCOM
						(dollars in t
BALANCE, January 1, 2000	3,010,189	$765	14,011,364	$141	$62,608	
Net income	-	-	-	-	-	
Common stock issued	-	-	43,697	-	100	
BALANCE, December 31, 2000	3,010,189	765	14,055,061	141	62,708	
Comprehensive income						
Net income	-	-	-	-	-	$ 9,5
Cumulative effect of change in accounting principle	-	-	-	-	-	(1,9
Reclassification adjustments for cumulative effect of change in accounting principle	-	-	-	-	-	1,9
Reclassification adjustments for settled contracts	-	-	-	-	-	(2,0
Net change in fair value of hedging instruments	-	-	-	-	-	2,7
Comprehensive income						$10,2
Common stock issued	-	-	9,016	-	28	
BALANCE, December 31, 2001	3,010,189	765	14,064,077	141	62,736	

Net income..................	-	-	-	-	-	4,7
Net change in fair value of hedging instruments........	-	-	-	-	-	(1,0
Comprehensive income						$ 3,6
Warrants issued............	252,632	15	-	-		
Common stock issued.........	-	-	113,306	1	488	
Dividends and accretion of discount on preferred stock......................	-	-	-	-		
BALANCE, December 31, 2002........................	3,262,821	$780	14,177,383	$142	$63,224	

	ACCUMULATED OTHER COMPREHENSIVE INCOME (LOSS)	SHAREHOLDERS' EQUITY
	(dollars in thousands)	
BALANCE, January 1, 2000....	-	$40,854
Net income..................	-	11,985
Common stock issued.........	-	100
BALANCE, December 31, 2000........................	-	52,939
Comprehensive income		
Net income..................	-	9,531
Cumulative effect of change in accounting principle....	$(1,967)	(1,967)
Reclassification adjustments for cumulative effect of change in accounting principle..................	1,967	1,967
Reclassification adjustments for settled contracts......	(2,020)	(2,020)
Net change in fair value of hedging instruments........	2,726	2,726
Comprehensive income		
Common stock issued.........	-	28
BALANCE, December 31, 2001........................	706	63,204
Net income..................	-	4,790
Net change in fair value of hedging instruments........	(1,094)	(1,094)
Comprehensive income		
Warrants issued............	-	15
Common stock issued.........	-	489
Dividends and accretion of discount on preferred stock......................	-	(588)
BALANCE, December 31,		

2002......................	$ (388)	$66,816
	=======	=======

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

CARRIZO OIL & GAS, INC.

CONSOLIDATED STATEMENTS OF CASH FLOWS

	FOR THE YEAR ENDED DECEMBER 31,		
	2000	2001	2002
	(in thousands)		
CASH FLOWS FROM OPERATING ACTIVITIES:			
Net Income..	$ 11,985	$ 9,531	$ 4,790
Adjustment to reconcile net income to net cash provided by operating activities--			
Depreciation, depletion and amortization...........	7,170	6,492	10,574
Discount accretion.................................	82	85	86
Ineffective derivative instruments.................	-	706	(706)
Interest payable in kind...........................	1,227	1,282	1,353
Stock option compensation (benefit)................	652	(558)	(84)
Gain on sale of Michael Petroleum Corporation......	-	(3,900)	-
Finders fee..	(1,544)	-	-
Deferred income taxes..............................	902	5,204	2,645
Changes in assets and liabilities--			
Accounts receivable................................	(2,968)	(719)	530
Deposits and other current assets..................	(625)	200	206
Other assets.......................................	(236)	(57)	(265)
Accounts payable...................................	(155)	6,555	643
Accrued liabilities................................	643	(870)	153
Net cash provided by operating activities........	17,133	23,951	19,925
CASH FLOWS FROM INVESTING ACTIVITIES:			
Capital expenditures................................	(19,746)	(38,264)	(24,696)
Proceeds from sale of Michael Petroleum Corporation...	-	5,445	-
Proceeds for sale of Metro Project...................	5,075	-	-
Proceeds from the sale of oil and natural gas properties..	-	-	355
Change in capital expenditure accrual................	(587)	355	(949)
Advances to operators................................	(490)	1,248	8
Advances for joint operations........................	(690)	(8)	1,182
Net cash used in investing activities...........	(16,438)	(31,224)	(24,100)
CASH FLOWS FROM FINANCING ACTIVITIES:			
Net proceeds from sale of common stock................	100	27	14
Net proceeds from sale of preferred stock.............	-	-	5,800
Net proceeds from debt issuance.......................	-	7,744	8,613
Debt repayments.......................................	(3,923)	(5,479)	(8,745)
Net cash provided by (used in) financing			

activities	(3,823)	2,292	5,682
NET INCREASE (DECREASE) IN CASH AND CASH EQUIVALENTS	(3,128)	(4,981)	1,507
CASH AND CASH EQUIVALENTS, beginning of year	11,345	8,217	3,236
CASH AND CASH EQUIVALENTS, end of year	$ 8,217	$ 3,236	$ 4,743
SUPPLEMENTAL CASH FLOW DISCLOSURES:			
Cash paid for interest (net of amounts capitalized)	$ -	$ -	$ 1
Cash paid for income taxes	$ -	$ -	$ -

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

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

1. NATURE OF OPERATIONS

Carrizo Oil & Gas, Inc. (Carrizo, a Texas corporation; together with its subsidiary, 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 on Texas and Louisiana Gulf Coast trends, primarily the Frio, Wilcox and Vicksburg trends. 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. CCBM has an obligation to fund $2.5 million of drilling costs on behalf of Rocky Mountain Gas, Inc. ("RMG"), from whom the interests in the leases were acquired. Through December 31, 2002, CCBM has satisfied $1.5 million of its drilling obligations on behalf of RMG.

The exploration for oil and natural gas is a business with a significant amount of inherent risk requiring large amounts of capital. The Company intends to finance its exploration and development program through cash from operations, existing credit facilities or arrangements with other industry participants. Should the sources of capital currently available to the Company not be sufficient to explore and develop its prospects and meet current and near-term obligations, the Company may be required to seek additional sources of financing which may not be available on terms acceptable to the Company. This lack of additional financing could force the Company to defer its planned exploration and development drilling program which could adversely affect the recoverability and ultimate value of the Company's oil and natural gas properties.

2. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

PRINCIPLES OF CONSOLIDATION

The consolidated financial statement are presented in accordance with generally accepted accounting principles in the United States. The consolidated financial statements include the accounts of the Company and its subsidiary. All intercompany accounts and transactions have been eliminated in consolidation.

CRITICAL ACCOUNTING POLICIES AND USE OF ESTIMATES

The preparation of financial statements in conformity with generally accepted accounting principles requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities at the date of the consolidated financial statements and the reported amounts of revenues and expenses during the reporting periods. Actual results could differ from these estimates.

The Company believes the following critical accounting policies affect its more significant judgements and estimates used in the preparation of its consolidated financial statements:

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 $0.9 million, $1.0 million and $1.0 million in 2000, 2001 and 2002, respectively. Maintenance and repairs are expensed as incurred.

Oil and natural gas properties are amortized based on the unit-of-production method using estimates of proved reserve quantities. Investments in unproved properties are not amortized 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 are impaired, the amount of impairment is added to the proved oil and natural gas 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 2000, 2001 and 2002 was $1.03, $1.15 and $1.41 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 of proved oil and natural gas properties are subject to a "ceiling test", which limits such costs to the estimated present value, discounted at a 10% interest rate, of future net revenues from proved reserves, based on current economic and operating conditions. If net capitalized costs exceed this limit, the excess is charged to operations through depreciation, depletion and amortization. No write-down of the Company's oil and natural gas assets was necessary in 2000, 2001 or 2002. Based on oil and natural gas prices in effect on December 31, 2001, the unamortized cost of oil and natural gas properties exceeded the cost center ceiling. As permitted by full cost accounting rules, improvements in pricing subsequent to December 31, 2001 removed the necessity to record a write-down. Using prices in effect on December 31, 2001 the pretax write-down would have been approximately $0.7 million. Because of the volatility of oil and natural gas prices, no assurance can be given that the Company will not experience a write-down in future periods.

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 and Fairchild and 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 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 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.

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.

FINANCING COSTS

Long-term debt financing costs of $0.8 million and $0.8 million are included in other assets as of December 31, 2001 and 2002, respectively, are being amortized using the effective yield method over the term of the loans (through January 31, 2005 for a credit facility and through December 15, 2007 for subordinated notes payable).

SUPPLEMENTAL CASH FLOW INFORMATION

The Statement of Cash Flows for the year ended December 31, 2002 does not reflect the following non-cash transactions: the $2.5 million of seismic data acquisitions, the acquisition $0.5 million in oil and natural gas properties through the issuance of common stock, and the $0.6 million reduction of oil and natural gas properties for the amount of insurance recoveries expected to be received related to difficulties encountered in the drilling of a well.

FINANCIAL INSTRUMENTS

The Company's recorded 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 amount of bank debt approximates fair value as this borrowing bears interest at floating market interest rates. The fair value of the Subordinated Notes payable and the RMG note at December 31, 2002 was $32.6 million and $5.6 million, respectively. Fair values for the Subordinated Notes payable and the RMG note were determined based upon interest rates available to the Company at December 31, 2002 with similar terms.

Stock-Based Compensation

The Company accounts for employee stock-based compensation using the intrinsic value method prescribed by Accounting Principles Board (APB) Opinion No. 25, "Accounting for Stock Issued to Employees" and related interpretations. Under this method, the Company records no compensation expense for stock options granted when the exercise price of those options is equal to or greater than the market price of the Company's common stock on the date of grant. Repriced options are accounted for as compensatory options using variable accounting treatment. Under variable plan accounting, compensation expense is adjusted for increases or decreases in the fair market value of the Company's common stock. Variable plan accounting is applied to the repriced options until the options are exercised, forfeited, or expire unexercised.

Derivative Instruments and Hedging Activities

In June 1998, the Financial Accounting Standards Board ("FASB") issued Statement of Financial Accounting Standards ("SFAS") No. 133 "Accounting for Derivative Instruments and Hedging Activities". This statement, as amended by SFAS No. 137 and SFAS No. 138, establishes standards of accounting for and disclosures of derivative instruments and hedging activities. This statement requires all derivative instruments to be carried on the balance sheet at fair value with changes in a derivative instrument's fair value recognized currently in earnings unless specific hedge accounting criteria are met.

SFAS No. 133 was effective for the Company beginning January 1, 2001 and was adopted by the Company on that date. In accordance with the current transition provisions of SFAS No. 133, the Company recorded a cumulative effect transition adjustment of $2.0 million (net of related tax expense of $1.1 million) in accumulated other comprehensive income to recognize the fair value of its derivatives designated as cash flow hedging instruments at the date of adoption.

Upon entering into a derivative contract, the Company designates the derivative instruments as a hedge of the variability of cash flow to be received (cash flow hedge). Changes in the fair value of a cash flow hedge are recorded in other comprehensive income to the extent that the derivative is effective in offsetting changes in the fair value of the hedged item. Any ineffectiveness in the relationship between the cash flow hedge and the hedged item is recognized currently in income. Gains and losses accumulated in other comprehensive income associated with the cash flow hedge are recognized in earnings as oil and natural gas revenues when the forecasted transaction occurs. All of the Company's derivative instruments at January 1, 2001, December 31, 2001 and December 31, 2002 were designated and effective as cash flow hedges except for its positions with an affiliate of Enron Corp. discussed in Note 12.

When hedge accounting is discontinued because it is probable that a forecasted transaction will not occur, the derivative will continue to be carried on the balance sheet at its fair value and gains and losses that were accumulated in other comprehensive income will be recognized in earnings immediately. In all other situations in which hedge accounting is discontinued, the derivative will be carried at fair value on the balance sheet with future changes in its fair value recognized in future earnings.

The Company typically uses fixed rate swaps and costless collars to hedge its exposure to material changes in the price of natural gas and oil. The Company formally documents all relationships between hedging instruments and hedged items, as well as its risk management objectives and strategy for undertaking various hedge transactions. This process includes linking all derivatives that are designated cash flow hedges to forecasted transactions. The Company also formally assesses, both at the hedge's inception and on an ongoing basis, whether the derivatives that are used in hedging transactions are highly effective in offsetting changes in cash flows of hedged transactions.

The Company's Board of Directors sets all of the Company's hedging policy, including volumes, types of instruments and counterparties, on a quarterly basis. These policies are implemented by management through the execution of trades 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 authorized 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 hedging activities quarterly.

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. Valuation allowances are established when necessary to reduce the deferred tax asset to the amount expected to be realized.

CONCENTRATION OF CREDIT RISK

Substantially all of the Company's accounts receivable result from oil and natural gas sales or joint interest billings to third parties in the oil and natural gas industry. 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 conditions. Historically, the Company has not experienced credit losses on such receivables. Derivative contracts subject the Company to concentration of credit risk. The Company transacts the majority of its derivative contracts with two counterparties. The Company does not require collateral from its customers.

MAJOR CUSTOMERS

The Company sold oil and natural gas production representing more than 10% of its oil and natural gas revenues for the year ended December 31, 2001 to Cokinos Natural Gas Company (17%); for the year ended December 31, 2002 to Cokinos Natural Gas Company (12%) and Discovery Producer Services, LLC (10%). Because alternate purchasers of oil and natural gas are readily available, the Company believes that the loss of any of its purchasers would not have a material adverse effect on the financial results of the Company.

EARNINGS PER SHARE

Supplemental earnings per share information is provided below:

	FOR THE YEAR ENDED DECEMBER 31,						
	INCOME			SHARES			P
	2000	2001	2002	2000	2001	2002	200
	(in thousands except share and per share amounts)						
Basic Earnings per Common Share:							
Net income............	$11,985	$9,531	$4,790				
Less: Dividends and Accretion of Discount on Preferred Shares....	-	-	588				
Net income available to common shareholders......	$11,985	$9,531	$4,202	14,028,176	14,059,151	14,158,438	$0.
Diluted Earnings per Common Share:							
Net Income............	$11,985	$9,531	$4,790	14,028,176	14,059,151	14,158,438	
Less: Dividends and Accretion of Discount on Preferred Shares....	-	-	588				
Stock Options.........				558,960	807,628	514,077	
Warrants..............				1,668,519	1,864,222	1,475,928	
Net income available to common shareholders......	$11,985	$9,531	$4,202	16,255,655	16,731,001	16,148,443	$0.

Basic earnings per common share has been computed by dividing net income by 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 period. The Company had outstanding 149,000, 79,500 and 172,333 stock options at December 31, 2000, 2001 and 2002, respectively, that were antidilutive. The Company had outstanding 252,632 warrants at December 31, 2002 that were antidilutive. These antidilutive stock options and warrants were not included in the calculation because the exercise price of these instruments exceeded the underlying market value of the options and warrants as of the dates presented. The Company had 1,145,515 convertible preferred shares at December 31, 2002 that were antidilutive and were not included in the calculation.

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.

NEW ACCOUNTING PRONOUNCEMENTS

In June 2001, the Financial Accounting Standards Board issued SFAS No. 143, "Accounting for Asset Retirement Obligations". This Statement is effective for fiscal years beginning after June 15, 2002, and the Company will adopt the Statement effective January 1, 2003. On January 1, 2003, the Company recorded $0.4 million as proved properties and $0.5 million as a liability for its plugging and abandonment expenses.

The Company has adopted the disclosure requirements of SFAS No. 148, "Accounting for Stock Based Compensation--Transition and Disclosure", issued in December 2002, effective with its December 31, 2002 consolidated financial statements and related footnotes.

3. INVESTMENT IN MICHAEL PETROLEUM CORPORATION

In 2000 the Company received a finder's fee valued at $1.5 million from affiliates of Donaldson, Lufkin & Jenrette ("DLJ") in connection with their purchase of a significant minority shareholder interest in Michael Petroleum Corporation ("MPC"). MPC is a privately held exploration and production company which focuses on the prolific natural gas producing Lobo Trend in South Texas. The minority shareholder interest in MPC was purchased by entities affiliated with DLJ. The Company elected to receive the fee in the form of 18,947 shares of common stock, 1.9% of the outstanding common shares of MPC, which, until its sale in 2001, was accounted for as a cost basis investment. Steven A. Webster, who is the Chairman of the Board of the Company, and a Managing Director of Global Energy Partners Ltd., a merchant banking affiliate of DLJ which makes investments in energy companies, joined the Board of Directors of MPC in connection with the transaction.

In 2001, the Company agreed to sell its interest in MPC pursuant to an agreement between MPC and its shareholders for the sale of a majority interest in MPC to Calpine Natural Gas Company. The Company received total cash proceeds of $5.7 million, of which $5.5 million was paid to the Company during the third quarter of 2001, resulting in a financial statement gain of $3.9 million being reflected in the third quarter 2001 financial results. The remaining amounts will be paid in 2003.

4. PROPERTY AND EQUIPMENT

At December 31, 2001 and 2002, property and equipment consisted of the following:

	AS OF DECEMBER 31,	
	2001	2002
	(in thousands)	
Proved oil and natural gas properties	$104,005	$133,032
Unproved oil and natural gas properties	44,416	42,020
Other equipment	609	685
Total property and equipment	149,030	175,737
Accumulated depreciation, depletion and amortization	(44,898)	(55,211)
Property and equipment, net	$104,132	$120,526

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. Of the $42.0 million of unproved property costs at December 31, 2002 being excluded from the amortizable base, $2.7 million, $11.7 million and $6.3 million were incurred in 2000, 2001 and 2002, respectively and $21.3 million was incurred in prior years. These costs are primarily seismic and

lease acquisition costs. 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:

	YEAR ENDED DECEMBER 31,		
	2000	2001	2002
	(in thousands)		
Provision at the statutory tax rate	$ 4,546	$5,204	$2,660
Decrease in valuation allowance pertaining to expected net operating loss utilization	(3,644)	-	-
Other	102	132	149
Income tax provision	$ 1,004	$5,336	$2,809

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, 2001 and 2002, the tax effects of these temporary differences resulted principally from the following:

	AS OF DECEMBER 31,	
	2001	2002
	(in thousands)	
Deferred income tax asset:		
Net operating loss carryforward	$1,797	$ 2,462

Hedge valuation	-	209
	1,797	2,671
Deferred income tax liabilities:		
Oil and gas acquisition, exploration and development costs deducted for tax purposes in excess of financial statement DD&A	4,084	6,309
Capitalized interest	2,734	3,819
	6,818	10,128
Net deferred income tax liability	$5,021	$ 7,457

The December 31, 2001 deferred income tax asset relating to the net operating loss carry forward and the deferred income tax liability relating to oil and natural gas acquisition, exploration and development costs deducted for tax purposes in excess of financial statement DD&A have been revised to reflect the 2001 results of operations as a reduction of the deferred income tax asset relating to the net operating loss carry forward. This revision adjustment resulted in a $1.4 million decrease in the deferred income tax asset relating to net operating loss carry forward and a corresponding decrease to the deferred income tax liability relating to oil and natural gas acquisition, exploration and development costs deducted for tax purposes in excess of financial statement DD&A. The net effect of these revisions resulted in no change to the net deferred income tax liability as reflected on the December 31, 2001 balance sheet.

The net deferred income tax liability is classified as follows:

	AS OF DECEMBER 31,	
	2001	2002
	(in thousands)	
Other current assets	$ -	$ 209
Deferred income taxes	5,021	7,666
Net deferred income tax liability	$5,021	$7,457

Realization of the net deferred tax asset 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 will be fully realized. The Company has net operating loss carryforwards totaling approximately $7.0 million, which begin expiring in 2012.

6. LONG-TERM DEBT

At December 31, 2001 and 2002, long-term debt consisted of the following:

	AS OF DECEMBER 31, 2001	AS OF DECEMBER 31, 2002
	(in thousands)	
Compass Facility	$ 7,166	$ -
Hibernia Facility	-	8,500
Senior subordinated notes, related parties	24,039	25,478
Capital lease obligations	233	267
Non-recourse note payable to RMG	6,750	5,250
	38,188	39,495
Less: current maturities	(2,107)	(1,609)
	$36,081	$37,886

On May 24, 2002, the Company entered into a credit agreement with Hibernia National Bank (the "Hibernia Facility") which matures on January 31, 2005, and repaid its existing facility with Compass Bank (the "Compass Facility"). The Hibernia Facility provides a revolving line of credit of up to $30.0 million. It is secured by substantially all of the Company's assets and is guaranteed by the Company's subsidiary.

The borrowing base will be determined by Hibernia National Bank at least semi-annually on each October 31 and April 30. The initial borrowing base was $12.0 million, and the borrowing base as of October 31, 2002 was $13.0 million. Each party to the credit agreement can request one unscheduled borrowing base determination subsequent to each scheduled determination. The borrowing base will at all times equal the borrowing base most recently determined by Hibernia National Bank, less quarterly borrowing base reductions required subsequent to such determination. Hibernia National Bank will reset the borrowing base amount at each scheduled and each unscheduled borrowing base determination date. The initial quarterly borrowing base reduction, which commenced on June 30, 2002, was $1.3 million. The quarterly borrowing base reduction effective January 31, 2003 is $1.8 million.

On December 12, 2002, the Company entered into an Amended and Restated Credit Agreement with Hibernia National Bank that provided additional availability under the Hibernia Facility in the amount of $2.5 million which is structured as an additional "Facility B" under the Hibernia Facility. As such, the total borrowing base under the Hibernia Facility as of December 31, 2002 was $15.5 million, of which $8.5 million is currently drawn. The Facility B bears interest at LIBOR plus 3.375%, is secured by certain leases and working interests in oil and natural gas wells and matures on April 30, 2003.

If the principal balance of the Hibernia Facility ever exceeds the borrowing base as reduced by the quarterly borrowing base reduction (as described above), the principal balance in excess of such reduced borrowing base will be due as of the date of such reduction. Otherwise, any unpaid principal or interest will be due at maturity.

If the principal balance of the Hibernia Facility ever exceeds any re-determined borrowing base, the Company has the option within thirty days to (individually or in combination): (i) make a lump sum payment curing the deficiency; (ii) pledge additional collateral sufficient in Hibernia National Bank's opinion to increase the borrowing base and cure the deficiency; or (iii) begin making equal monthly principal payments that will cure the deficiency within the ensuing six-month period. Such payments are in addition to any payments that may come due as a result of the quarterly borrowing base reductions.

For each tranche of principal borrowed under the revolving line of credit, the interest rate will be, at the Company's option: (i) the Eurodollar Rate, plus an applicable margin equal to 2.375% if the amount borrowed is greater than or equal to 90% of the borrowing base, 2.0% if the amount borrowed is less than 90%, but greater than or equal to 50% of the borrowing base, or 1.625% if the amount borrowed is less than 50% of the borrowing base; or (ii) the Base Rate, plus an applicable margin of 0.375% if the amount borrowed is greater than or equal to 90% of the borrowing base. Interest on Eurodollar Loans is payable on either the last day of each Eurodollar option period or monthly, whichever is earlier. Interest on Base Rate Loans is payable monthly.

The Company is subject to certain covenants under the terms of the Hibernia Facility, including, but not limited to the maintenance of the following financial covenants: (i) a minimum current ratio of 1.0 to 1.0 (including availability under the borrowing base), (ii) a minimum quarterly debt services coverage of 1.25 times, and (iii) a minimum shareholders equity equal to $56.0 million, plus 100% of all subsequent common and preferred equity contributed by shareholders, plus 50% of all positive earning occurring subsequent to such quarter end, all ratios as more particularly discussed in the credit facility. The Hibernia Facility also places restrictions on additional indebtedness, dividends to non-preferred stockholders, liens, investments, mergers, acquisitions, asset dispositions, asset pledges and mortgages, change of control, repurchase or redemption for cash of the Company's common or preferred stock, speculative commodity transactions, and other matters.

At December 31, 2001, amounts outstanding under the Compass Facility totaled $7.2 million, with an additional $0.6 million available for future borrowings. At December 31, 2002, amounts outstanding under the Hibernia Facility totaled $8.5 million with an additional $4.3 million available for future borrowings. No amounts under the Compass Facility were outstanding at December 31, 2002. At December 31, 2001, one letter of credit was issued and outstanding under the Compass Facility in the amount of $0.2 million. At December 31, 2002, one letter of credit was issued and outstanding under the Hibernia Facility in the amount of $0.2 million.

On June 29, 2001, CCBM, Inc., a wholly owned subsidiary of the Company ("CCBM"), issued a non-recourse promissory note payable in the amount of $7.5 million to RMG as consideration for certain interests in oil and natural gas leases held by RMG in Wyoming and Montana. The RMG note is payable in 41-monthly principal payments of $0.1 million plus interest at 8% per annum commencing July 31, 2001 with the balance due December 31, 2004. The RMG note is secured solely by CCBM's interests in the oil and natural gas leases in Wyoming and Montana. At December 31, 2001 and 2002, the outstanding principal balance of this note was $6.8 million and $5.3 million, respectively.

In December 2001, the Company entered into a capital lease agreement secured by certain production equipment in the amount of $0.2 million. The lease is payable in one payment of $11,323 and 35 monthly payments of $7,549 including interest at 8.6% per annum. In October 2002, the Company entered a capital lease agreement secured by certain production equipment in the amount of $0.1 million. The lease is payable in 36 monthly payments of $3,462 including interest at 6.4% per annum. The Company has the option to acquire the equipment at the conclusion of the lease for $1, under both leases. DD&A on the capital leases for year ended December 31, 2002 amounted to $28,000 and accumulated DD&A on the leased equipment at December 31, 2002 amounted to $28,000.

In December 1999, the Company consummated the sale of $22.0 million principal amount of 9% Senior Subordinated Notes due 2007 (the "Subordinated Notes") and $8.0 million of common stock and Warrants. The Company sold $17.6 million, $2.2 million, $0.8 million, $0.8 million and $0.8 million principal amount of Subordinated Notes; 2,909,092, 363,636, 121,212, 121,212 and 121,212 shares of the Company's common stock and 2,208,152, 276,019, 92,006, 92,006 and 92,006 Warrants to CB Capital Investors, L.P. (now JPMorgan), Mellon, Paul B. Loyd, Jr., Steven A. Webster and Douglas A.P. Hamilton, respectively. The Subordinated Notes were sold at a discount of $0.7 million, which is being amortized over the life of the notes. Interest payments are due quarterly commencing on March 31, 2000. The Company may elect, for a period of up to five years, to increase the amount of the Subordinated Notes for 60% of the interest which would otherwise be payable in cash. As of December 31, 2001 and 2002, the outstanding balance of the Subordinated Notes had been increased by $2.6 million and $3.9 million, respectively, for such interest paid in kind.

The Company is subject to certain covenants under the terms under the Subordinated Notes securities purchase agreement, including but not limited to, (a) maintenance of a specified tangible net worth, (b) maintenance of a ratio of EBITDA (earnings before interest, taxes, depreciation and amortization) to quarterly Debt Service (as defined in the agreement) of not less than 1.00 to 1.00, and (c) a limitation of its capital expenditures to an amount equal to the Company's EBITDA for the immediately prior fiscal year (unless approved by the Company's Board of Directors and a JPMorgan appointed director).

Estimated maturities of long-term debt are $1.6 million in 2003, $3.9 million in 2004, $8.5 million in 2005 and the remainder in 2007.

At December 31, 2002, the Company believes it was in compliance with all of its debt covenants.

7. SEISMIC OBLIGATION PAYABLE

In 2002 the Company acquired (or obtained the right to acquire) certain seismic data in its core areas in the Texas and Louisiana Gulf Coast regions. Under the terms of the acquisition agreements, the Company is required to make monthly payments of $0.1 million through March 2004 and additional payments of $0.8 million are due in April 2004.

8. 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 Carrizo 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 and Steven A. Webster, respectively. The Series B Preferred Stock is convertible into common stock by the investors at a conversion price of $5.70 per share, subject to adjustments, and is initially convertible into 1,052,632 shares of common stock. Dividends on the Series B Preferred Stock will be 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, 2002, the outstanding balance of the Series B Preferred Stock has been increased by $0.5 million (5,294 shares) for dividends paid in kind. The Series B Preferred Stock is 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 will also participate in any dividends declared on the common stock. Holders of the Series B Preferred Stock will receive a liquidation preference upon the liquidation of, or certain mergers or sales of substantially all assets involving, the Company. Such holders will also have the option of receiving a change of control repayment price upon certain deemed change of control transactions. The warrants have a five-year term and entitle 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 are exercisable at any time after issuance. The warrants may be exercised on a cashless exercise basis.

Net proceeds of this financing were approximately $5.8 million and were used primarily to fund the Company's ongoing exploration and development program and general corporate purposes.

9. 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 July 2001, the Company was notified of a prior lease in favor of a predecessor of ExxonMobil purporting to be valid and covering the same property as the Company's Neblett lease in Starr County, Texas. The Neblett lease is part of a unit in N. La Copita Prospect in which the Company owns a non-operating interest. The operator of the lease, GMT, filed a petition for, and was granted, a temporary restraining order against ExxonMobil in the 229th Judicial Court in Starr County, Texas enjoining ExxonMobil from taking possession of the Neblett wells. Pending resolution of the underlying title issue, the temporary restraining order was extended voluntarily by agreement of the parties, conditioned on GMT paying the revenues into escrow and agreeing to provide ExxonMobil with certain discovery materials in this action. ExxonMobil has filed a counterclaim against GMT and all the non-operators, including the Company, to establish the validity of their lease, remove cloud on title, quiet title to the property, and for conversion, trespass and punitive damages. The Company, along with GMT and other partners, reached a final settlement with ExxonMobil on February 11, 2003. Under the terms of the settlement, the Company recovered the balance of its drilling costs (approximately $0.1 million) and certain other costs and retained no further interest in the property. No reserves with respect to these properties were included in the Company's reported proved reserves as of December 31, 2001 and 2002.

During August 2001, the Company entered into an agreement whereby the lessor will provide to the Company up to $0.8 million in financing for production equipment utilizing capital leases. At December 31, 2002, two leases in the amount of $0.5 million had been executed under this facility.

At December 31, 2002, the Company was obligated under a noncancelable operating lease for office space. Rent expense for the years ended December 31, 2000, 2001 and 2002 was $0.2 million. The Company is obligated for remaining lease payments of $0.2 million per year through December 31, 2004.

CCBM has an obligation to fund $2.5 million of drilling costs on behalf of RMG. Through December 31, 2002, CCBM has satisfied $1.5 million of its drilling obligations on behalf of RMG.

10. SHAREHOLDERS' EQUITY

The Company issued 9,016 and 113,306 shares of common stock valued at $28,000 and $0.5 million for the years ended December 31, 2001 and 2002, respectively. Of these shares, 106,472 were issued as partial consideration for the acquisition of interests in certain oil and natural gas properties during 2002.

The following table summarizes information for the options outstanding at December 31, 2002:

	OPTIONS OUTSTANDING			OPTIONS EXERCI	
RANGE OF EXERCISE PRICES	NUMBER OF OPTIONS OUTSTANDING AT 12/31/02	WEIGHTED AVERAGE REMAINING CONTRACTUAL LIFE IN YEARS	WEIGHTED AVERAGE EXERCISE PRICE	NUMBER OF OPTIONS EXERCISABLE AT 12/31/02	W A E
$1.75-2.25.........................	718,870	7.04	$2.19	522,203	
$3.14-4.00.........................	341,120	5.34	$3.21	279,453	
$4.01-5.00.........................	420,500	8.88	$4.26	136,000	
$5.17-8.00.........................	149,833	6.88	$6.71	110,555	

In June of 1997, the Company established the Incentive Plan of Carrizo Oil & Gas, Inc. (the "Incentive Plan"). In October 1995, the FASB issued SFAS No. 123, "Accounting for Stock-Based Compensation", which requires the Company to record stock-based compensation at fair value. In December 2002, the FASB issued SFAS No. 148, "Accounting for Stock Based Compensation--Transition and Disclosure". The Company has adopted the disclosure requirements of SFAS No. 148 and has elected to record employee compensation expense utilizing the intrinsic value method permitted under Accounting Principles Board (APB) Opinion No. 25, "Accounting for Stock Issued to Employees". The Company accounts for its employees' stock-based compensation plan under APB Opinion No. 25 and its related interpretations. Accordingly, any deferred compensation expense would be recorded for stock options based on the excess of the market value of the common stock on the date the options were granted over the aggregate exercise price of the options. This deferred compensation would be amortized over the vesting period of each option. Had compensation cost been determined consistent with SFAS No. 123 "Accounting for Stock Based Compensation" for all options, the Company's net income (loss) and earnings per share would have been as follows:

2000	2001	2002
(in thousands except per share amounts)		

Net income as reported	$11,985	$ 9,531	$4,790
Less: Total stock-based employee compensation expense determined under fair value method for all awards, net of related tax effects	(498)	(1,369)	(872)
Pro forma net income	$11,487	$ 8,162	$3,918
Net income per common share, as reported:			
Basic	$ 0.85	$ 0.68	$ 0.30
Diluted	0.74	0.57	0.26
Pro Forma net income per common share, as if value method had been applied to all awards:			
Basic	$ 0.82	$ 0.58	$ 0.28
Diluted	0.71	0.49	0.24

The fair value of each option grant was estimated on the date of grant using the Black-Scholes option pricing model with the following assumptions used for grants in 2000, 2001 and 2002: risk free interest rate of 6.7%, 4.9% and 4.8%, respectively, expected dividend yield of 0%, expected life of 10 years and expected volatility of 70.8%, 80.7% and 77.7% respectively.

The Company may grant options ("Incentive Plan Options") to purchase up to 1,850,000 shares under the Incentive Plan and has granted options on 1,566,000 shares through December 31, 2002. Through

December 31, 2002, 56,797 stock options had been exercised. A summary of the status of the Company's stock options at December 31, 2000, 2001 and 2002 is presented in the table below:

	2000		
	SHARES	WEIGHTED AVERAGE EXERCISE PRICES	RANGE OF EXERCISE PRICES
Outstanding at beginning of year	827,120	$6.01	$1.75 - $8.00
Granted (Incentive Plan Options)	425,000	$3.85	$2.20 - $8.00
Exercised (Pre-IPO Options)	(3,000)	$3.60	$3.60
Exercised (Incentive Plan Options)	(40,697)	$2.20	$2.00 - $6.00
Expired (Incentive Plan Options)	(2,000)	$3.50	$3.50
Outstanding at end of year	1,206,423	$5.20	$2.00 - $8.00
Exercisable at end of year	316,388	$3.79	
Weighted average of fair value of options granted during the year	$ 2.94		

2001

	SHARES	WEIGHTED AVERAGE EXERCISE PRICES	RANGE OF EXERCISE PRICES
Outstanding at beginning of year	1,206,423	$5.20	$1.75 - $8.00
Granted (Incentive Plan Options)	436,500	$4.34	$4.01 - $7.40
Exercised (Pre-IPO Options)	(3,000)	$3.60	$3.60
Exercised (Incentive Plan Options)	(3,266)	$2.13	$2.00 - $2.25
Outstanding at end of year	1,636,657	$3.49	$1.75 - $8.00
Exercisable at end of year	625,701	$3.45	
Weighted average of fair value of options granted during the year	$ 3.57		

	2002		
	SHARES	WEIGHTED AVERAGE EXERCISE PRICES	RANGE OF EXERCISE PRICES
Outstanding at beginning of year	1,636,657	$3.49	$1.75 - $8.00
Granted (Incentive Plan Options)	54,500	$4.31	$3.76 - $5.37
Exercised (Incentive Plan Options)	(6,834)	$2.12	$2.00 - $2.25
Expired (Incentive Plan Options)	(54,000)	$6.38	$1.75 - $8.00
Outstanding at end of year	1,630,323	$3.35	$1.75 - $8.00
Exercisable at end of year	1,048,212	$3.28	
Weighted average of fair value of options granted during the year	$ 3.57		

In March of 2000, the FASB issued Interpretation No. 44 "Accounting for Certain Transactions involving Stock Compensation--an interpretation of APB No. 25" ("the Interpretation") which was effective July 1, 2000 and clarifies the application of APB No. 25 for certain issues associated with the issuance or subsequent modifications of stock compensation. For certain modifications, including stock option repricings made subsequent to December 15, 1998, the Interpretation requires that variable plan accounting be applied to those modified awards prospectively from July 1, 2000. This requires that the change in the intrinsic value of the modified awards be recognized as compensation expense. On February 17, 2000, Carrizo repriced certain employee and director stock options covering 348,500 shares of stock with a weighted average exercise price of $9.13 to a new exercise price of $2.25 through the cancellation of existing options and issuance of new options at current market prices. Subsequent to the adoption of the Interpretation, the Company is required to record the effects of any changes in its stock price over the remaining vesting period through February 2010 on the corresponding intrinsic value of the repriced options in its results of operations as compensation expense until the repriced options either are exercised or expire. Stock option compensation expense (benefit) relating to the repriced options for the years ended December 31, 2001 and 2002 amounted to $(0.6 million) and $(0.1 million), respectively.

11. RELATED-PARTY TRANSACTIONS

During the years ended December 31, 2001 and 2002, the Company incurred drilling costs in the amount of $6.3 million and $2.9 million, respectively, with Grey Wolf Drilling. Mr. Webster is the Chairman of the Board of Carrizo and a member of the Board of Directors of Grey Wolf Drilling. It is management's opinion that these transactions with Grey Wolf were performed at prevailing market rates.

At December 31, 2002, the Company had outstanding related party accounts receivable, payable and advances for joint operations balances of $1.2 million, $1.2 million and $0.3 million, respectively.

During the years ended December 31, 2001 and 2002, the Company participated in the drilling of two wells and one well, respectively, that were operated by a subsidiary of Brigham Exploration Company. During the year ended December 31, 2002, Brigham Exploration Company ("Brigham") participated in the drilling of two wells operated by the Company. Mr. Webster is a member of the Board of Directors of Brigham. Mr. Webster is also a managing director of a merchant banking affiliate of the beneficial owner of approximately 35% of the common stock of the parent company of Brigham Oil and Gas, LP. The terms of the operating agreements between the Company and Brigham are consistent with standard industry practices.

During the year ended December 31, 2002, the Company sold a 2% working interest in certain leases in Matagorda County, TX to Mr. Webster. The terms of the sale were the same as other sales of working interests in the same leases to industry partners.

See Notes 6 and 8 for a discussion of the Subordinated Notes and Series B Preferred Stock, respectively, with parties that include members of the Company's Board of Directors.

In December 1999, the Company reduced the exercise price of certain warrants originally issued to affiliates of Enron Corp. in January 1998. There were 250,000 of these warrants that expire in January 2005 to purchase the Company's common stock at $4.00 per share outstanding as of December 31, 2001 and 2002.

12. DERIVATIVE INSTRUMENTS AND HEDGING ACTIVITY

The Company's operations involve managing market risks related to changes in commodity prices. Derivative financial instruments, specifically swaps, futures, options and other contracts, are used to reduce and manage those risks. The Company addresses market risk by selecting instruments whose value fluctuations correlate strongly with the underlying commodity being hedged. The Company enters into swaps, options, collars and other derivative contracts to hedge the price risks associated with a portion of anticipated future oil and natural gas production. While the use of hedging arrangements 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 expiration or exchanged for physical delivery contracts. The Company enters into the majority of its hedging transactions with two counterparties and a netting agreement is 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 hedging transaction.

In November 2001, the Company had no-cost collars with an affiliate of Enron Corp., designated as hedges, covering 2,553,000 MMBtu of natural gas production from December 2001 through December 2002. The value of these derivatives at that time was $0.8 million. Because of Enron's financial condition, the Company concluded that the derivatives contracts were no longer effective and thus did not qualify for hedge accounting treatment. As required by SFAS No. 133, the value of these derivative instruments as of November 2001 $(0.8 million) was recorded in accumulated other comprehensive income and will be reclassified into earnings over the original term of the derivative instruments. An allowance for the related asset totalling $0.8 million, net of tax of $0.4 million, was charged to other expense. At December 31, 2001, $0.7 million, net of tax of $0.4 million, remained in accumulated other comprehensive income related to the deferred gains on these derivatives. The remaining balance in other comprehensive income was reported as oil and natural gas revenues in 2002 as the terms of the original derivative expired.

As of December 31, 2002, $0.4 million, net of tax of $0.2 million, remained in accumulated other comprehensive income related to the valuation of the Company's hedging positions.

Total oil purchased and sold under swaps and collars during 2000, 2001 and 2002 were 87,900 Bbls, 18,000 Bbls and 131,300 Bbls, respectively. Total natural gas purchased and sold under swaps and collars in 2000, 2001 and 2002 were 1,590,000 MMBtu and 3,087,000 MMBtu and 2,314,000 MMBtu, respectively. The net gains and (losses) realized by the Company under such hedging arrangements were $(1.5 million), $2.0 million and $(0.9 million) for 2000, 2001 and 2002, respectively, and are included in oil and natural gas revenues.

At December 31, 2001 the Company had no derivative instruments outstanding designated as hedge positions. At December 31, 2002 the Company had the following outstanding hedge positions:

	DECEMBER 31, 2002				
	CONTRACT VOLUMES				
QUARTER	BBLS	MMBTU	AVERAGE FIXED PRICE	AVERAGE FLOOR PRICE	AV CEILI
First Quarter 2003..................	27,000		$24.85		
First Quarter 2003..................	36,000			$23.50	$2
First Quarter 2003..................		540,000		3.40	
Second Quarter 2003.................	27,300		24.85		
Second Quarter 2003.................	36,000			23.50	2
Second Quarter 2003.................		546,000		3.40	
Third Quarter 2003..................		552,000		3.40	
Fourth Quarter 2003.................		552,000		3.40	

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

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

COSTS INCURRED

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

	YEAR ENDED DECEMBER 31,		
	2000	2001	2002
	(in thousands)		
Property acquisition costs			
Unproved	$ 6,641	$12,607	$ 6,402
Proved	337	800	660
Exploration cost	7,843	18,356	14,194
Development costs	1,361	3,065	2,351
Total costs incurred(1)	$16,182	$34,828	$23,607

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(1) Excludes capitalized interest on unproved properties of $3.6 million, $3.2 million and $3.1 million for the years ended December 31, 2000, 2001 and 2002, 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, 2001 and 2002, and the related discounted future net cash flows before income taxes are based on estimates prepared by Ryder Scott Company and Fairchild and Wells, Inc., 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:

THOUSANDS OF BARRELS OF
OIL AND CONDENSATE
AT DECEMBER 31,

	2000	2001	2002
Proved developed and undeveloped reserves--			
Beginning of year	4,877	6,397	6,857
Discoveries and extensions	93	600	369
Revisions	1,625	20	1,568
Sales of oil and gas properties in place	-	-	(12)
Production	(198)	(160)	(401)
End of year	6,397	6,857	8,381
Proved developed reserves at beginning of year	1,070	1,017	1,158
Proved developed reserves at end of year	1,017	1,158	1,393

	MILLIONS OF CUBIC FEET OF NATURAL GAS AT DECEMBER 31,		
	2000	2001	2002
Proved developed and undeveloped reserves--			
Beginning of year	11,323	10,992	17,858
Purchases of oil and gas properties in place	-	-	585
Discoveries and extensions	4,179	12,560	3,280
Revisions	1,553	(1,262)	(3,726)
Sales of oil and gas properties in place	(603)	-	(274)
Production	(5,460)	(4,432)	(4,801)
End of year	10,992	17,858	12,922
Proved developed reserves at beginning of year	10,680	10,351	13,754
Proved developed reserves at end of year	10,351	13,754	12,826

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,		
	2000	2001	2002
	(in thousands)		
Future cash inflows	$266,725	$169,856	$305,087

Future oil and natural gas operating expenses	126,526	76,348	138,106
Future development costs	14,284	16,083	15,259
Future income tax expenses	25,242	5,822	32,133
Future net cash flows	100,673	71,603	119,589
10% annual discount for estimating timing of cash flows	30,567	27,026	54,292
Standard measure of discounted future net cash flows	$ 70,106	$ 44,577	$ 65,297

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 2000, 2001 and 2002 future cash flows were $24.85, $17.71 and $29.16 for oil, respectively and $10.34, $2.76 and $4.70 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 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:

	YEAR ENDED DECEMBER 31,		
	2000	2001	2002
	(in thousands)		
Changes due to current-year operations--			
Sales of oil and natural gas, net of oil and natural gas operating expenses	$(21,893)	$(23,622)	$(23,377)
Extensions and discoveries	26,214	28,009	20,680
Purchases of oil and gas properties	-	-	888
Changes due to revisions in standardized variables			
Prices and operating expenses	16,686	(38,472)	37,023
Income taxes	(14,090)	13,367	(14,692)
Estimated future development costs	(1,122)	(1,070)	417
Revision of quantities	2,921	(1,109)	8,910
Sales of reserves in place	(254)	-	(191)
Accretion of discount	4,736	8,768	4,820
Production rates, timing and other	14,178	(11,400)	(13,758)
Net change	27,376	(25,529)	20,720

Beginning of year	42,730	70,106	44,577
End of year	$ 70,106	$ 44,577	$ 65,297

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 an after-tax basis.

SUPPLEMENTAL QUARTERLY FINANCIAL DATA

	FIRST	SECOND	THIRD	FOU
		(unaudited) (in thousands except per share amoun		
2002				
Revenues	$4,027	$6,780	$6,752	$9,
Costs and expenses, net	3,883	5,706	5,576	6,
Net income	144	1,074	1,176	2,
Dividends and accretion	74	168	173	
Net income available to common shareholders	$ 70	$ 906	$1,003	$2,
Basic net income per share(1)	$ 0.00	$ 0.06	$ 0.07	$ 0
Diluted net income per share(1)	$ 0.00	$ 0.06	$ 0.06	$ 0
2001				
Revenues	$8,727	$7,092	$6,162	$4,
Costs and expenses, net	5,263	4,792	2,616	4,
Net income	$3,464	$2,300	$3,546	$
Basic net income per share(1)	$ 0.25	$ 0.16	$ 0.25	$ 0
Diluted net income per share(1)	$ 0.21	$ 0.14	$ 0.22	$ 0

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(1) The sum of individual quarterly net income per common share may not agree with year-to-date net income per common share as each period's computation is based on the weighted average number of common shares outstanding during that period.

CARRIZO OIL & GAS, INC.

CONSOLIDATED BALANCE SHEETS

	DECEMBER 31, 2002	SEPTEMBER 30, 2003
	(unaudited) (in thousands)	
ASSETS		
CURRENT ASSETS:		
Cash and cash equivalents	$ 4,743	$ 4,426
Accounts receivable, trade (net of allowance for doubtful accounts of $0.5 million at December 31, 2002 and September 30, 2003, respectively)	8,207	8,643
Advances to operators	501	2,697
Other current assets	651	92
Total current assets	14,102	15,858
PROPERTY AND EQUIPMENT, net (full-cost method of accounting for oil and natural gas properties)	120,526	124,030
Investment in Pinnacle Gas Resources, Inc. (Note 4)	-	7,101
Deferred financing costs	760	646
	$135,388	$147,635
LIABILITIES AND SHAREHOLDERS' EQUITY		
CURRENT LIABILITIES:		
Accounts payable, trade	$ 9,957	$ 13,502
Accrued liabilities	1,014	1,466
Advances for joint operations	1,550	3,222
Current maturities of long-term debt	1,609	811
Current maturities of seismic obligation payable	1,414	1,456
Total current liabilities	15,544	20,457
LONG-TERM DEBT	37,886	34,154
SEISMIC OBLIGATION PAYABLE	1,103	-
ASSET RETIREMENT OBLIGATION	-	704
DEFERRED INCOME TAXES	7,666	11,326
COMMITMENTS AND CONTINGENCIES (Note 7)		
CONVERTIBLE PARTICIPATING PREFERRED STOCK (10,000,000 shares of preferred stock authorized, of which 150,000 are shares designated as convertible participating shares, with 65,294 and 68,559 convertible participating shares issued and outstanding at December 31, 2002 and September 30, 2003, respectively) (Note 8)	6,373	6,925
SHAREHOLDERS' EQUITY:		
Warrants (3,262,821 outstanding at December 31, 2002 and September 30, 2003, respectively)	780	780
Common stock, par value $.01 (40,000,000 shares authorized with 14,177,383 and 14,385,551 issued and outstanding at December 31, 2002 and September 30, 2003, respectively)	142	144
Additional paid in capital	63,224	63,821
Retained earnings	3,058	9,391
Accumulated other comprehensive loss	(388)	(67)
	66,816	74,069
	$135,388	$147,635

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

CARRIZO OIL & GAS, INC.

CONSOLIDATED STATEMENTS OF OPERATIONS

	FOR THE THREE MONTHS ENDED SEPTEMBER 30,		FOR THE NIN MONTHS ENDE SEPTEMBER 3	
	2002	2003	2002	20
	(unaudited) (in thousands except per shar amounts)			
OIL AND NATURAL GAS REVENUES	$6,753	$10,123	$17,559	$29
COSTS AND EXPENSES:				
Oil and natural gas operating expenses (exclusive of depreciation shown separately below)	1,334	1,587	3,687	5
Depreciation, depletion and amortization	2,726	3,086	7,332	8
General and administrative	990	1,624	3,049	4
Accretion expense related to asset retirement obligations	-	11	-	
Stock option compensation	(14)	296	(70)	
Total costs and expenses	5,036	6,604	13,998	18
OPERATING INCOME	1,717	3,519	3,561	11
OTHER INCOME AND EXPENSES:				
Equity in loss of Pinnacle Gas Resources, Inc.	-	(168)	-	
Other income and expenses	117	(17)	245	
Interest income	16	13	44	
Interest expense	(58)	(103)	(169)	
Interest expense, related parties	(590)	(599)	(2,023)	(1
Capitalized interest	648	696	2,192	2
INCOME BEFORE INCOME TAXES	1,850	3,341	3,850	11
INCOME TAXES (Note 6)	674	1,259	1,456	4
NET INCOME BEFORE CUMULATIVE EFFECT OF CHANGE IN ACCOUNTING PRINCIPLE	1,176	2,082	2,394	7
DIVIDENDS AND ACCRETION ON PREFERRED STOCK	173	190	415	
NET INCOME AVAILABLE TO COMMON SHAREHOLDERS BEFORE CUMULATIVE EFFECT OF CHANGE IN ACCOUNTING PRINCIPLE	1,003	1,892	1,979	6
CUMULATIVE EFFECT OF CHANGE IN ACCOUNTING PRINCIPLE	-	-	-	
NET INCOME AVAILABLE TO COMMON SHAREHOLDERS	$1,003	$ 1,892	$ 1,979	$ 6
BASIC EARNINGS PER COMMON SHARE BEFORE CUMULATIVE EFFECT OF CHANGE IN ACCOUNTING PRINCIPLE	$ 0.07	$ 0.13	$ 0.14	$
CUMULATIVE EFFECT OF CHANGE IN ACCOUNTING PRINCIPLE NET OF INCOME TAXES	-	-	-	(
BASIC EARNINGS PER COMMON SHARE	$ 0.07	$ 0.13	$ 0.14	$
DILUTED EARNINGS PER COMMON SHARE BEFORE CUMULATIVE EFFECT OF CHANGE IN ACCOUNTING PRINCIPLE	$ 0.06	$ 0.11	$ 0.12	$

CUMULATIVE EFFECT OF CHANGE IN ACCOUNTING PRINCIPLE NET OF INCOME TAXES	-	-	-	(
DILUTED EARNINGS PER COMMON SHARE	$ 0.06	$ 0.11	$ 0.12	$
PRO FORMA AMOUNTS ASSUMING ASSET RETIREMENTS OBLIGATION IS APPLIED RETROACTIVELY:				
BASIC EARNINGS PER COMMON SHARE	$ 0.07	$ 0.13	$ 0.14	$
DILUTED EARNINGS PER COMMON SHARE	$ 0.06	$ 0.11	$ 0.12	$

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

CARRIZO OIL & GAS, INC.

CONSOLIDATED STATEMENTS OF CASH FLOWS
(unaudited)

	FOR THE NINE MONTHS ENDED SEPTEMBER 30,	
	2002	2003
	(in thousands)	
CASH FLOWS FROM OPERATING ACTIVITIES:		
Net income before cumulative effect of change in accounting principle	$ 2,394	$ 7,013
Adjustment to reconcile net income to net cash provided by operating activities-		
Depreciation, depletion and amortization	7,332	8,727
Discount accretion	64	93
Equity in loss of Pinnacle Gas Resources, Inc.	-	177
Ineffective derivative instruments	(548)	-
Interest payable in kind	1,008	1,063
Stock option compensation (benefit)	(70)	319
Deferred income taxes	1,333	3,918
Changes in assets and liabilities-		
Accounts receivable	1,302	(436)
Other assets	(744)	326
Accounts payable	107	1,682
Other liabilities	161	627
Net cash provided by operating activities	12,339	23,509
CASH FLOWS FROM INVESTING ACTIVITIES:		
Capital expenditures	(20,854)	(20,368)
Change in capital expenditure accrual	3,496	1,864
Advances to operators	(33)	(2,196)
Advances for joint operations	647	1,672
Net cash used in investing activities	(16,744)	(19,028)
CASH FLOWS FROM FINANCING ACTIVITIES:		
Net proceeds from the sale of common stock	13	599

Net proceeds from the sale of preferred stock	5,785	-
Net proceeds from the sale of warrants	15	-
Advances under Borrowing Base Credit Facility	6,500	-
Debt repayments	(8,346)	(5,397)
Net cash provided by (used in) financing activities	3,967	(4,798)
NET INCREASE (DECREASE) IN CASH AND CASH EQUIVALENTS	(438)	(317)
CASH AND CASH EQUIVALENTS, beginning of period	3,236	4,743
CASH AND CASH EQUIVALENTS, end of period	$ 2,798	$ 4,426
SUPPLEMENTAL CASH FLOW DISCLOSURES:		
Cash paid for interest (net of amounts capitalized)	$ -	$ -
Cash paid for income taxes	$ -	$ -
Common stock issued for oil and gas property (Note 8)	$ 475	$ -

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

CARRIZO OIL & GAS, INC.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS
(unaudited)

1. ACCOUNTING POLICIES

The consolidated financial statements included herein have been prepared by Carrizo Oil & Gas, Inc. (the Company), and are unaudited, except for the balance sheet at December 31, 2002, which has been prepared from the audited financial statements at that date. The financial statements reflect the accounts of the Company and its subsidiary 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. Certain information and footnote disclosures normally included in financial statements prepared in accordance with generally accepted accounting principles have been omitted pursuant to the rules and regulations of the Securities and Exchange Commission (SEC). The Company believes that the disclosures presented are adequate to allow the information presented not to be misleading. The financial statements included herein should be read in conjunction with the audited financial statements and notes thereto included in the Company's Annual Report on Form 10-K for the year ended December 31, 2002.

2. MAJOR CUSTOMERS

The Company sold oil and natural gas production representing more than 10% of its oil and natural gas revenues for the nine months ended September 30, 2002 to Cokinos Natural Gas Company (11%); for the nine months ended September 30, 2003 to Gulfmark Energy, Inc. (17%), Cokinos Natural Gas Company (15%) and WMJ Investments Corp. (14%). Because alternate purchasers of oil and natural gas are readily available, the Company believes that the loss of any of its purchaser would not have a material adverse effect on the financial results of the Company.

3. EARNINGS PER COMMON SHARE

Supplemental earnings per share information is provided below:

FOR THE THREE MONTHS ENDED SEPTEMBER 30,

(in thousands except share and per share amounts)

	INCOME 2002	INCOME 2003	SHARES 2002	SHARES 2003	PER-SHARE AMOUNT 2002	PER-SHARE AMOUNT 2003
Net income	$1,176	$2,082				
Less: Dividends and Accretion of Discount on Preferred Shares	(173)	(190)				
Basic Earnings per Share Net income available to common shareholders	1,003	1,892	14,176,528	14,264,639	$0.07	$0.13
Dilutive effect of Stock Options, Warrants and Preferred Stock conversions	-	-	1,725,826	2,625,991		
Diluted Earnings per Share Net income available to common shareholders plus assumed conversions	$1,003	$1,892	15,902,354	16,890,630	$0.06	$0.11

FOR THE NINE MONTHS ENDED SEPTEMBER 30,

(in thousands except share and per share amounts)

	INCOME 2002	INCOME 2003	SHARES 2002	SHARES 2003	PER-SHARE AMO 2002	20
Net income before cumulative effect of change in accounting principle	$2,394	$7,013				
Less: Dividends and Accretion of Discount on Preferred Shares	(415)	(552)				
Basic Earnings per Share Net income available to common shareholders	1,979	6,461	14,152,239	14,224,893	$0.14	$0.
Dilutive effect of Stock Options, Warrants and Preferred Stock conversions	-	-	1,776,091	2,349,345		

Diluted Earnings per Share						
Net income available to common shareholders plus assumed conversions................	$1,979	$6,461	15,928,330	16,574,238	$0.12	$0.

	FOR THE NINE MONTHS ENDED SEPTEMBER 30,					
	INCOME		SHARES		PER-SHARE AMOUN	
	2002	2003	2002	2003	2002	2003
	(in thousands except share and per share amounts)					
Cumulative effect of change in accounting principle net of income taxes..................	$ -	$(128)				
Basic Earnings per Share						
Net loss available to common shareholders...............	-	-	14,152,239	14,224,893	$0.00	$(0.0
Dilutive effect of Stock Options, Warrants and Preferred Stock conversions...................	-	-	1,776,091	2,349,345		
Diluted Earnings per Share						
Net income available to common shareholders plus assumed conversions................	$ -	$(128)	15,928,330	16,574,238	$0.00	$(0.0

	FOR THE NINE MONTHS ENDED SEPTEMBER 30,					
	INCOME		SHARES		PER-SHARE AMO	
	2002	2003	2002	2003	2002	20
	(in thousands except share and per share amounts)					
Net income......................	$2,394	$6,885				
Less: Dividends and Accretion of Discount on Preferred Shares.......................	(415)	(552)				
Basic Earnings per Share						
Net income available to common shareholders..............	1,979	6,333	14,152,239	14,224,893	$0.14	$0.
Dilutive effect of Stock Options, Warrants and Preferred Stock conversions...	-	-	1,776,091	2,349,345		
Diluted Earnings per Share						

Net income available to common shareholders plus assumed conversions................	$1,979	$6,333	15,928,330	16,574,238	$0.12	$0.
	======	======	==========	==========	=====	===

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 393,833 and 57,000 stock options and 252,632 and zero warrants during the three months ended September 30, 2002 and 2003, respectively, which were antidilutive and were not included in the calculation because the exercise price of these instruments exceeded the underlying market value of the options and warrants. The Company had outstanding 406,833 and 129,000 stock options and 252,632 warrants during the nine months ended September 30, 2002 and 2003, respectively, which were antidilutive and were not included in the calculation because the exercise price of these instruments exceeded the underlying market value of the options and warrants. At September 30, 2002 and 2003, the Company also had 1,090,649 and 1,202,791 shares, respectively, based on the assumed conversion of the Series B Convertible Participating Preferred Stock, that were antidilutive and were not included in the calculation.

4. 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. ("CCBM"), 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 gas reserves in the Bobcat project area to a newly formed entity, Pinnacle Gas Resources, Inc., a Delaware corporation ("Pinnacle"). 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"). CCBM no longer has a drilling obligation in connection with the oil and natural gas leases contributed to Pinnacle (see "General Overview" in Management's Discussion and Analysis of Financial Condition and Results of Operations for a further discussion).

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. The CSFB Parties currently have greater than 50% of the voting power of the Pinnacle capital stock through their ownership of Pinnacle Common Stock and Pinnacle Preferred Stock.

Currently, on a fully diluted basis, assuming that all parties exercised their Pinnacle Warrants and Pinnacle Options, the CSFB Parties, CCBM and RMG would have ownership interests of approximately 46.2%, 26.9% and 26.9%, respectively. On a fully-diluted basis, assuming the additional $11.8 million of cash was contributed by the CSFB Parties and all Pinnacle Warrants and Pinnacle Options were exercised by all parties, the CSFB Parties would own 54.6% of Pinnacle and CCBM and RMG would each own 22.7% of Pinnacle.

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 approximately 36,529 gross acres prospective for coalbed methane development in the Powder River Basin of Wyoming from Gastar Exploration, Ltd. The leases include 95 producing coalbed methane wells currently in the early stages of dewatering. These wells are producing at a combined gross rate of approximately 2.5 MMcfd, or an estimated 1 MMcfd net to Pinnacle. 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 will be 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. As of June 30, 2003, Pinnacle owned interests in approximately 131,000 gross acres in the Powder River Basin.

Prior to and in connection with its contribution of assets to Pinnacle, CCBM paid RMG approximately $1.8 million in cash as part of its outstanding purchase obligation on the coalbed methane property interests CCBM previously acquired from RMG. The approximate $1.0 million remaining balance of CCBM's obligation to RMG is scheduled to be paid in monthly installments of approximately $52,805 through November 2004 and a balloon payment on December 31, 2004. The RMG note is secured solely by CCBM's interests in the remaining oil and natural gas leases in Wyoming and Montana. In connection with the Company's investment in Pinnacle, the Company received a reduction in the principal amount of the RMG note of approximately $1.5 million and relinquished the right to receive certain revenues related to the properties contributed to Pinnacle.

CCBM continues its coalbed methane business activities and, in addition to its interest in Pinnacle, owns direct interests in approximately 189,000 gross acres of 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 and RMG will continue to conduct exploration and development activities on these properties as well as pursue other potential acquisitions. The Bobcat property was producing approximately 400 Mcfe of coalbed methane gas net to CCBM's interest immediately prior to its contribution to Pinnacle. Other than indirectly through Pinnacle, CCBM currently has no proved reserves of, and is no longer receiving revenue from, coalbed methane gas.

ACCOUNTING AND TAX TREATMENT

For accounting purposes, the transaction will be 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 FASB issued Interpretation 46, "Consolidation of Variable Interest Entities" ("FIN 46"), in January 2003. FIN 46 requires the consolidation of certain types of entities in which a company absorbs a majority of another entity's expected losses, receives a majority of the other entity's expected residual returns, or both, as a result of ownership, contractual or other financial interests in the other entity. These entities are called "variable interest entities". The provisions of FIN 46 are effective for the Company in the second quarter for new transactions or entities formed in 2003 and in the third quarter for transactions or entities formed prior to 2003.

If an entity is determined to be a "variable interest entity" ("VIE"), the entity must be consolidated by the "primary beneficiary". The primary beneficiary is the holder of the variable interests that absorbs a majority of the variable interest entity's expected losses or receives a majority of the entity's residual returns in the event no holder has a majority of the expected losses. The determination of the primary beneficiary is based on projected cash flows at the inception of the variable interests. Because Steven A. Webster, Chairman of Carrizo, is also a managing director of Credit Suisse First Boston (see "Related Parties in the Pinnacle Transaction" below), Carrizo could be defined as the primary beneficiary if the projected cash flows analysis indicated losses in excess of the equity invested. The initial determination of whether an entity is a VIE is to be reconsidered only when one or more of the following occur (1) the entity's governing documents or the contractual arrangements among the parties involved change, (2) the equity investment of some part thereof is returned to the investors, and other parties become exposed to expected losses or (3) the entity undertakes additional activities or acquires additional assets that increase the entity's expected losses.

We have determined that we should not consolidate Pinnacle, under FIN 46, because our current projected cash flow analysis of Pinnacle's operations at inception indicates that Pinnacle is not a VIE. Accordingly, our investment in Pinnacle has been recorded using the equity method of accounting.

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 sheet included in this Form 10-Q for the nine months ended September 30, 2003.

RELATED PARTIES IN THE PINNACLE TRANSACTION

Steven A. Webster, Chairman of the Board of the Company, is also a managing director of Credit Suisse First Boston Private Equity and is therefore a related party to this transaction.

TRANSITION SERVICES AGREEMENT

The Company entered into a transition services agreement with Pinnacle pursuant to which the Company will provide certain accounting, treasury, tax, insurance and financial reporting functions to Pinnacle through the end of 2003 for a monthly fee equal to the Company's actual cost to provide such services. After December 31, 2003, the agreement will automatically renew on a quarterly basis unless one of the parties gives notice of its intent to terminate the agreement.

Similarly, Pinnacle has also entered into a transition services agreement with RMG to provide Pinnacle assistance in setting up operational accounting and management systems for a monthly fee equal to the actual cost to provide such services. After December 31, 2003, the agreement will automatically renew on a quarterly basis unless one of the parties gives notice of its intent to terminate the agreement.

5. LONG-TERM DEBT

At December 31, 2002 and September 30, 2003, long-term debt consisted of the following:

	DECEMBER 31, 2002	SEPTEMBER 30, 2003
Borrowing base facility....................................	$ 8,500	$ 7,000
Senior subordinated notes, related parties.................	25,478	26,605
Capital lease obligations..................................	267	338
Non-recourse note payable to Rocky Mountain Gas, Inc.	5,250	1,022
	39,495	34,965
Less: current maturities..................................	(1,609)	(811)
	$37,886	$34,154

On May 24, 2002, the Company entered into a credit agreement with Hibernia National Bank (the "Hibernia Facility") which matures on January 31, 2005, and repaid its existing facility with Compass Bank (the "Compass Facility"). The Hibernia Facility provides a revolving line of credit of up to $30.0 million. It is secured by substantially all of the Company's producing oil and gas properties assets and is guaranteed by the Company's wholly owned subsidiary CCBM, Inc.

The borrowing base will be determined by Hibernia National Bank at least semi-annually on each October 31 and April 30. The initial borrowing base was $12.0 million, and the borrowing base as of September 30, 2003 was $13.5 million. Each party to the credit agreement can request one unscheduled borrowing base determination subsequent to each scheduled determination. The borrowing base will at all times equal the borrowing base most recently determined by Hibernia National Bank, less quarterly borrowing base reductions required subsequent to such determination. Hibernia National Bank will reset the borrowing base amount at each scheduled and each unscheduled borrowing base determination date. The initial quarterly borrowing base reduction, which commenced on June 30, 2002, was $1.3 million. The quarterly borrowing base reduction effective January 31, 2003 was $1.8 million. There was an increase in the borrowing base for the quarter ended June 30, 2003 of $2.2 million.

On December 12, 2002, the Company entered into an Amended and Restated Credit Agreement with Hibernia National Bank that provided additional availability under the Hibernia Facility in the amount of $2.5 million which was structured as an additional "Facility B" under the Hibernia Facility. As such, the total borrowing base under the Hibernia Facility as of December 31, 2002 and September 30, 2003 was $15.5 million and $13.5 million, respectively, of which $8.5 million and $7.0 million was outstanding on December 31, 2002 and September 30, 2003, respectively. The Facility B bore interest at LIBOR plus 3.375%, was secured by certain leases and working interests in oil and natural gas wells and matured on April 30, 2003.

If the principal balance of the Hibernia Facility ever exceeds the borrowing base as reduced by the quarterly borrowing base reduction (as described above), the principal balance in excess of such reduced borrowing base will be due as of the date of such reduction. Otherwise, any unpaid principal or interest will be due at maturity.

If the principal balance of the Hibernia Facility ever exceeds any re-determined borrowing base, the Company has the option within thirty days to (individually or in combination): (i) make a lump sum payment curing the deficiency; (ii) pledge additional collateral sufficient in Hibernia National Bank's opinion to increase the borrowing base and cure the deficiency; or (iii) begin making equal monthly principal payments that will cure the deficiency within the ensuing six-month period. Such payments are in addition to any payments that may come due as a result of the quarterly borrowing base reductions.

For each tranche of principal borrowed under the revolving line of credit, the interest rate will be, at the Company's option: (i) the Eurodollar Rate, plus an applicable margin equal to 2.375% if the amount borrowed is greater than or equal to 90% of the borrowing base, 2.0% if the amount borrowed is less than

90% but greater than or equal to 50% of the borrowing base, or 1.625% if the amount borrowed is less than 50% of the borrowing base; or (ii) the Base Rate, plus an applicable margin of 0.375% if the amount borrowed is greater than or equal to 90% of the borrowing base. Interest on Eurodollar Loans is payable on either the last day of each Eurodollar option period or monthly, whichever is earlier. Interest on Base Rate Loans is payable monthly.

The Company is subject to certain covenants under the terms of the Hibernia Facility, including, but not limited to the maintenance of the following financial covenants: (i) a minimum current ratio of 1.0 to 1.0 (including availability under the borrowing base), (ii) a minimum quarterly debt services coverage of 1.25 times, and (iii) a minimum shareholders equity equal to $56.0 million, plus 100% of all subsequent common and preferred equity contributed by shareholders, plus 50% of all positive earning occurring subsequent to such quarter end, all ratios as more particularly discussed in the credit facility. The Hibernia Facility also places restrictions on additional indebtedness, dividends to non-preferred stockholders, liens, investments, mergers, acquisitions, asset dispositions, asset pledges and mortgages, change of control, repurchase or redemption for cash of the Company's common or preferred stock, speculative commodity transactions, and other matters.

At December 31, 2002 and September 30, 2003, amounts outstanding under the Hibernia Facility totaled $8.5 million and $7.0 million, respectively, with an additional $4.3 million and $6.5 million, respectively, under Facility A and $2.5 million under Facility B at December 31, 2002 available for future borrowings. No amounts under the Compass Facility were outstanding at December 31, 2002. At December 31, 2002 and September 30, 2003, one letter of credit was issued and outstanding under the Hibernia Facility in the amount of $0.2 million.

On June 29, 2001, CCBM, Inc., a wholly owned subsidiary of the Company ("CCBM"), issued a non-recourse promissory note payable in the amount of $7.5 million to RMG as consideration for certain interests in oil and natural gas leases held by RMG in Wyoming and Montana. The RMG note was payable in 41 monthly principal payments of $0.1 million plus interest at 8% per annum commencing July 31, 2001 with the balance due December 31, 2004. The RMG note is secured solely by CCBM's interests in the oil and natural gas leases in Wyoming and Montana. At December 31, 2002 and September 30, 2003, the outstanding principal balance of this note was $5.3 million and $1.0 million, respectively. In connection with the Company's investment in Pinnacle (see Note 3), the Company received a reduction in the principal amount of the RMG note of approximately $1.5 million and relinquished the right to certain revenues related to the properties contributed to Pinnacle.

In December 2001, the Company entered into a capital lease agreement secured by certain production equipment in the amount of $0.2 million. The lease is payable in one payment of $11,323 and 35 monthly payments of $7,549 including interest at 8.6% per annum. In October 2002, the Company entered into a capital lease agreement secured by certain production equipment in the amount of $0.1 million. The lease is payable in 36 monthly payments of $3,462 including interest at 6.4% per annum. In May 2003, the Company entered into a capital lease agreement secured by certain production equipment in the amount of $0.1 million. The lease is payable in 36 monthly payments of $3,030 including interest at 5.5% per annum. In August 2003, the Company entered into a capital lease agreement secured by certain production equipment in the amount of $0.1 million. The lease is payable in 36 monthly payments of $2,179 including interest at 6.0% per annum. The Company has the option to acquire the equipment at the conclusion of the lease for $1 under all of these leases. DD&A on the capital leases for the three months ended September 30, 2002 and 2003 amounted to $6,000 and $14,000, respectively. DD&A on the capital leases for the nine months ended September 30, 2002 and 2003 amounted to $18,000 and $35,000 respectively, and accumulated DD&A on the leased equipment at December 31, 2002 and September 30, 2003 amounted to $28,000 and $62,000, respectively.

In December 1999, the Company consummated the sale of $22.0 million principal amount of 9% Senior Subordinated Notes due 2007 (the "Subordinated Notes") and $8.0 million of common stock and Warrants. The Company sold $17.6 million, $2.2 million, $0.8 million, $0.8 million and $0.8 million principal amount of Subordinated Notes; 2,909,092, 363,636, 121,212, 121,212 and 121,212 shares of the

Company's common stock and 2,208,152, 276,019, 92,006, 92,006 and 92,006 Warrants to CB Capital Investors, L.P. (now known as J.P. Morgan Partners (23A SBIC), LLC), Mellon Ventures, L.P., Paul B. Loyd, Jr., Steven A. Webster and Douglas A.P. Hamilton, respectively. The Subordinated Notes were sold at a discount of $0.7 million, which is being amortized over the life of the notes. Interest payments are due quarterly commencing on March 31, 2000. The Company may elect, until December 2004, to increase the amount of the Subordinated Notes for 60% of the interest which would otherwise be payable in cash. As of December 31, 2002 and September 30, 2003, the outstanding balance of the Subordinated Notes had been increased by $3.9 million and $5.0 million, respectively, for such interest paid in kind.

The Company is subject to certain covenants under the terms of the Subordinated Notes securities purchase agreement, including but not limited to, (a) maintenance of a specified tangible net worth, (b) maintenance of a ratio of EBITDA (earnings before interest, taxes, depreciation and amortization) to quarterly Debt Service (as defined in the agreement) of not less than 1.00 to 1.00, and (c) a limitation of its capital expenditures to an amount equal to the Company's EBITDA for the immediately prior fiscal year (unless approved by the Company's Board of Directors and a J.P. Morgan Partners (23A SBIC), LLC appointed director), as well as limits on the Company's ability to (i) incur indebtedness, (ii) incur or allow liens, (iii) engage in mergers, consolidation, sales of assets and acquisitions, (iv) declare dividends and effect certain distributions (including restrictions on distributions upon the Common Stock), (v) engage in transactions with affiliates and (vi) make certain repayments and prepayments, including any prepayment of the subordinated debt, indebtedness that is guaranteed or credit-enhanced by any affiliate of the Company, and prepayments that effect certain permanent reductions in revolving credit facilities. EBITDA was part of a negotiated covenant with the purchasers and is presented here as a disclosure of the Company's covenant obligations.

At December 31, 2002 and September 30, 2003, the Company believes it was in compliance with all of its debt covenants.

6. INCOME TAXES

The Company estimates its annual effective tax rate to be approximately 35%, which also approximates its statutory rate. The Company provided deferred tax expense of $0.6 million and $1.2 million for the three months ended September

30, 2002 and 2003, respectively, and $1.3 million and $3.9 million for the nine months ended September 30, 2002 and 2003, respectively.

7. COMMITMENTS AND CONTINGENCIES

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

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

Pursuant to agreements entered into with RMG in June 2001, CCBM has an obligation to fund $2.5 million of drilling costs on behalf of RMG. Through September 30, 2003, CCBM had satisfied $2.2 million of the drilling obligation on behalf of RMG.

8. 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 Carrizo's 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 and Steven A. Webster, respectively. The Series B Preferred Stock is convertible into common stock by the investors at a conversion price of $5.70 per share, subject to adjustments, and is initially convertible into 1,052,632 shares of common stock. Dividends on the Series B Preferred Stock will be 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, 2002 and September 30, 2003, the outstanding balance of the Series B Preferred Stock had been increased by $0.5 million (5,294 shares) and $0.9 million (8,559 shares), respectively, for dividends paid in kind. At September 30, 2003, the Company had accrued a dividend of $0.2 million (1,714 shares) that is payable on December 31, 2003. The Series B Preferred Stock is 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 will also participate in any dividends declared on the common stock. Holders of the Series B Preferred Stock will receive a liquidation preference upon the liquidation of, or certain mergers or sales of substantially all assets involving, the Company. Such holders will also have the option of receiving a change of control repayment price upon certain deemed change of control transactions. The warrants have a five-year term and entitle 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 are exercisable at any time after issuance. The warrants may be exercised on a cashless exercise basis.

Net proceeds of this financing were approximately $5.8 million and were used primarily to fund the Company's ongoing exploration and development program and for general corporate purposes.

9. SHAREHOLDER'S EQUITY

The Company issued 106,472 and 208,168 shares of common stock during the nine months ended September 30, 2002 and 2003, respectively. The shares issued during the nine months ended September 30, 2002 were partial consideration for the acquisition of an interest in certain oil and natural gas properties and the shares issued during the nine months ended September 30, 2003 were the result of the exercise of options granted under the Company's Incentive Plan.

In June of 1997, the Company established the Incentive Plan of Carrizo Oil & Gas, Inc. (the "Incentive Plan"). In October 1995, the FASB issued SFAS No. 123, "Accounting for Stock-Based Compensation", which requires the Company to record stock-based compensation at fair value. In December 2002, the FASB issued SFAS No. 148, "Accounting for Stock Based Compensation--Transition and Disclosure". The Company has adopted the disclosure requirements of SFAS No. 148 and has elected to record employee compensation expense utilizing the intrinsic value method permitted under Accounting Principles Board (APB) Opinion No. 25, "Accounting for Stock Issued to Employees". The Company accounts for its employees' stock-based compensation plan under APB Opinion No. 25 and its related interpretations. Accordingly, any deferred compensation expense would be recorded for stock options based on the excess of the market value of the common stock on the date the options were granted over the aggregate exercise price of the options. This deferred compensation would be amortized over the vesting period of each option. Had compensation cost been determined consistent with SFAS No. 123 "Accounting for Stock-

Based Compensation" for all options, the Company's net income (loss) and earnings per share would have been as follows:

	FOR THE THREE MONTHS ENDED SEPTEMBER 30,		FOR THE N MONTHS EN SEPTEMBER
	2002	2003	2002
	(in thousands except per share amounts)		(in thous except per share am
Net income available to common shareholders, as reported	$1,003	$1,892	$1,979
Less: Total stock-based employee compensation expense determined under fair value method for all awards, net of related tax effects	(193)	(132)	(452)
Pro forma net income (loss) available to common shareholders	$ 810	$1,760	$1,527
Net income per common share, as reported:			
Basic	$ 0.07	$ 0.13	$ 0.14
Diluted	0.06	0.11	0.12
Pro Forma net income (loss) per common share, as if value method had been applied to all awards:			
Basic	$ 0.06	$ 0.12	$ 0.11
Diluted	0.05	0.10	0.10

Diluted earnings per share amounts for the three months ended September 30, 2002 and 2003 are based upon 15,902,354 and 16,890,630 shares, respectively, that include the dilutive effect of assumed stock option and warrant exercises of 1,725,826 and 2,625,911, respectively. Diluted earnings per share amounts for the nine months ended September 30, 2002 and 2003 are based upon 15,928,330 and 16,574,238 shares, respectively, that include the dilutive effect of assumed stock options and warrant exercises of 1,776,091 and 2,349,345, respectively.

Comprehensive income for the three and nine months ended September 30, 2002 and 2003 was as follows:

	FOR THE THREE MONTHS ENDED SEPTEMBER 30,		FOR THE NINE MONTHS ENDED SEPTEMBER 30,	
	2002	2003	2002	2003
Net income	$1,176	$2,082	$ 2,394	$6,885
Net change in fair value of hedging instruments	(586)	612	(1,083)	321
Comprehensive income	$ 590	$2,694	$ 1,311	$7,206

10. CHANGE IN ACCOUNTING PRINCIPLE

In June 2001, the Financial Accounting Standards Board issued SFAS No. 143, "Accounting for Asset Retirement Obligations". This Statement is effective for fiscal years beginning after June 15, 2002, and the Company adopted the Statement effective January 1, 2003. During the three months ended March 31, 2003, the Company recorded a cumulative effect of change in accounting principle of $0.1 million, $0.4 million as proved properties and $0.5 million as a liability for its plugging and abandonment expenses. The Company includes Asset Retirement Obligation costs, liabilities and related discounted cash flows in its ceiling test calculations.

11. DERIVATIVE INSTRUMENTS AND HEDGING ACTIVITY

The Company's operations involve managing market risks related to changes in commodity prices. Derivative financial instruments, specifically swaps, futures, options and other contracts, are used to reduce and manage those risks. The Company addresses market risk by selecting instruments whose value fluctuations correlate strongly with the underlying commodity being hedged. The Company enters into

swaps, options, collars and other derivative contracts to hedge the price risks associated with a portion of anticipated future oil and natural gas production. While the use of hedging arrangements 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 expiration or exchanged for physical delivery contracts. The Company enters into the majority of its hedging transactions with two counterparties and a netting agreement is 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 hedging transaction.

As of December 31, 2002 and September 30, 2003, $0.4 million and $67,000, net of tax of $0.2 million and $36,000, respectively, remained in accumulated other comprehensive income related to the valuation of the Company's hedging positions.

Total oil purchased and sold under swaps and collars during the three months ended September 30, 2002 and 2003 was 33,600 Bbls and 24,400 Bbls, respectively. Total natural gas purchased and sold under swaps and collars during the three months ended September 30, 2002 and 2003 was 731,000 MMBtu and 828,000 MMBtu, respectively. Total oil purchased and sold under swaps and collars during the nine months ended September 30, 2002 and 2003 was 79,100 Bbls and 150,700 Bbls, respectively. Total natural gas purchased and sold under swaps and collars during the nine months ended September 30, 2002 and 2003 was 3,094,000 MMBtu and 2,187,000 MMBtu, respectively. The net losses realized by the Company under such hedging arrangements was $0.1 million and $0.1 million for the three months ended September 30, 2002 and 2003, respectively, and are included in oil and natural gas revenues. The net losses realized by the Company under such hedging arrangements were $0.4 million and $1.8 million for the nine months ended September 30, 2002 and 2003, respectively, and are included in oil and natural gas revenues.

At December 31, 2002 and September 30, 2003 the Company had the following outstanding hedge positions:

	AS OF DECEMBER 31, 2002				
	CONTRACT VOLUMES				
QUARTER	BBLS	MMBTU	AVERAGE FIXED PRICE	AVERAGE FLOOR PRICE	AVERA CEILING
First Quarter 2003..................	27,000		$24.85		
First Quarter 2003..................	36,000			$23.50	$26.5
First Quarter 2003..................		540,000		3.40	5.2
Second Quarter 2003.................	27,300		24.85		
Second Quarter 2003.................	36,000			23.50	26.5
Second Quarter 2003.................		546,000		3.40	5.2
Third Quarter 2003..................		552,000		3.40	5.2
Fourth Quarter 2003.................		552,000		3.40	5.2

	AS OF SEPTEMBER 30, 2003				
	CONTRACT VOLUMES				
QUARTER	BBLS	MMBTU	AVERAGE FIXED PRICE	AVERAGE FLOOR PRICE	AVERA CEILING

Fourth Quarter 2003..................	30,700		$30.22		
Fourth Quarter 2003..................		552,000		3.40	5.25
First Quarter 2004...................		546,000		4.10	7.00
Second Quarter 2004..................		273,000		4.00	5.20
Third Quarter 2004...................		276,000		4.00	5.20
Fourth Quarter 2004..................		93,000		4.00	5.20

During October 2003, the Company entered into swap arrangements covering 30,200 Bbls of oil for November 2003 through February 2004 production with an average fixed price of $30.26.

In addition to the hedge positions above, during the second quarter of 2003, the Company acquired options to sell 6,000 MMBtu of natural gas per day for the period July 2003 through August 2003 (552,000 MMBtu) at $8.00 per MMBtu for approximately $119,000. The Company acquired these options to protect its cash position against potential margin calls on certain natural gas derivatives due to large increases in the price of natural gas. These options were classified as derivatives. As of September 30, 2003, these options have expired and a charge of $28,000 and $119,000 has been included in other income and expense for the three and nine months ended September 30, 2003, respectively.

12. NEW ACCOUNTING PRONOUNCEMENTS

The FASB issued Interpretation 46, "Consolidation of Variable Interest Entities" ("FIN 46"), in January 2003. FIN 46 requires the consolidation of certain types of entities in which a company absorbs a majority of another entity's expected losses, receives a majority of the other entity's expected residual returns, or both, as a result of ownership, contractual or other financial interests in the other entity. The Company has identified no transactions or related entities that required consolidation under this interpretation.

SFAS No. 141, "Business Combinations," and SFAS No. 142, "Goodwill and Intangible Assets," were issued by the FASB in June 2001 and became effective for us on July 1, 2001 and January 1, 2002, respectively. SFAS No. 141 requires all business combinations initiated after June 30, 2001 to be accounted for using the purchase method. Additionally, SFAS No. 141 requires companies to disaggregate and report separately from goodwill certain intangible assets. SFAS No. 142 establishes new guidelines for accounting for goodwill and other intangible assets. Under SFAS No. 142, goodwill and certain other intangible assets are not amortized but rather are reviewed annually for impairment.

Natural gas and oil mineral rights held under lease and other contractual arrangements representing the right to extract such reserves for both undeveloped and developed leaseholds may have to be classified separately from natural gas and oil properties as intangible assets on our consolidated balance sheets. In addition, the disclosures required by SFAS No. 141 and 142 relative to intangibles would be included in the notes to the consolidated financial statements. Historically, we, like many other natural gas and oil companies, have included these rights as part of natural gas and oil properties, even after SFAS No. 141 and 142 became effective.

In the event this interpretation is adopted, a substantial portion of the acquisition costs of oil and gas properties would be required to be classified on the balance sheet as an intangible asset. The Company would not be required to reclassify proved reserve leasehold acquisitions prior to June 30, 2001 because the Company did not separately value or account for these costs prior to the adoption date of SFAS No. 141. The Company believes this interpretation would not have a material effect on our results of operations for the periods presented or in the future as these intangible assets would be depleted using the units of production method in a manner consistent with the method currently used to calculate depletion, depreciation, and amortization expense ("DD&A") on those assets.

As of September 30, 2003, December 31, 2002 and December 31, 2001, we had leasehold costs incurred of approximately $3.4 million, $1.4 million and $1.4 million, respectively, that would be classified on our consolidated balance sheet as "intangible leasehold costs" if we applied the interpretation discussed above.

13. SUBSEQUENT EVENTS

EXCHANGE TRANSACTION ON OCTOBER 10, 2003

Pursuant to an exchange election provided in a letter agreement, dated May 1, 2001, with certain participants in the Carrizo 2001 Seismic and Acreage Program (the "2001 Program"), the Company is issuing to such participants, who have exercised their election, approximately 168,000 shares of its common stock in exchange for the participants' entire interest in the 2001 Program, including approximately 350 square miles of 3-D seismic data and working interests in certain producing properties. The exchange transaction was effective on October 10, 2003 and was valued using the closing price of the Company's stock on that date, for a total of approximately $1.2 million.

APPENDIX A TO PROSPECTUS

SUMMARY RESERVE REPORTS

March 26, 2003

Carrizo Oil & Gas, Inc.

14701 St. Mary's Lane, Suite 800
Houston, Texas 77079

Gentlemen:

At your request, we have prepared an estimate of the reserves, future production, and income attributable to certain leasehold and royalty interests of Carrizo Oil & Gas, Inc. (Carrizo) as of December 31, 2002. The subject properties are located in the states of Louisiana and Texas. The income data were estimated using the Securities and Exchange Commission (SEC) guidelines for future price and cost parameters.

The estimated reserves and future income amounts presented in this report are related to hydrocarbon prices. December 31, 2002 hydrocarbon prices were used in the preparation of this report as required by SEC guidelines; however, actual future prices may vary significantly from December 31, 2002 prices. Therefore, volumes of reserves actually recovered and amounts of income actually received may differ significantly from the estimated quantities presented in this report. The results of this study are summarized below.

SEC PARAMETERS
ESTIMATED NET RESERVES AND INCOME DATA
CERTAIN LEASEHOLD AND ROYALTY INTERESTS OF
CARRIZO OIL & GAS, INC.
AS OF DECEMBER 31, 2002

	PROVED		
	DEVELOPED		
	PRODUCING	NON-PRODUCING	TOTAL PROVED
NET REMAINING RESERVES			
Oil/Condensate -- Barrels	428,969	214,238	643,207
Plant Products -- Barrels	25,964	83,660	109,624
Gas -- MMCF	5,592	6,087	11,679
INCOME DATA ($M)			
Future Gross Revenue	$37,853.6	$35,042.8	$72,896.4
Deductions	7,544.7	6,633.4	14,178.1
Future Net Income (FNI)	$30,308.9	$28,409.4	$58,718.3
Discounted FNI @ 10%	$26,627.8	$20,572.8	$47,200.6

Liquid hydrocarbons are expressed in standard 42 gallon barrels. All gas volumes are sales gas expressed in millions of cubic feet (MMCF) at the official temperature and pressure bases of the areas in which the gas reserves are located.

The future gross revenue is after the deduction of production taxes. The deductions are comprised of the normal direct costs of operating the wells, ad valorem taxes, recompletion costs, development costs, and certain abandonment costs net of salvage. The future net income is before the deduction of state and federal income taxes and general administrative overhead, and has not been adjusted for outstanding loans that may exist nor does it include any adjustment for cash on hand or undistributed income. No attempt was made to quantify or otherwise account for any accumulated gas production imbalances that may exist. Gas reserves account for approximately 73 percent and liquid hydrocarbon reserves account for the remaining 27 percent of total future gross revenue from proved reserves.

RESERVES INCLUDED IN THIS REPORT

The proved reserves included herein conform to the definition as set forth in the Securities and Exchange Commission's Regulation S-X Part 210.4-10 (a) as clarified by subsequent Commission Staff Accounting Bulletins. The definitions of proved reserves are included in the section entitled "Petroleum Reserves Definitions" which is attached with this report.

The proved and probable developed non-producing reserves included herein are comprised of shut-in and behind pipe categories. The various reserve status categories are defined in the section entitled "Petroleum Reserves Definitions" which is attached with this report.

ESTIMATES OF RESERVES

In general, the reserves included herein were estimated by performance methods or the volumetric method; however, other methods were used in certain cases where characteristics of the data indicated such other methods were more appropriate in our opinion. The reserves estimated by the performance method utilized extrapolations of various historical data in those cases where such data were definitive. Reserves were estimated by the volumetric method in those cases where there were inadequate historical performance data to establish a definitive trend or where the use of production performance data as a basis for the reserve estimates was considered to be inappropriate.

The reserves included in this report are estimates only and should not be construed as being exact quantities. They may or may not be actually recovered, and if recovered, the revenues therefrom and the actual costs related thereto could be more or less than the estimated amounts. Moreover, estimates of reserves may increase or decrease as a result of future operations.

FUTURE PRODUCTION RATES

Initial production rates are based on the current producing rates for those wells now on production. Test data and other related information were used to estimate the anticipated initial production rates for those wells or locations which are not currently producing. If no production decline trend has been established, future production rates were held constant, or adjusted for the effects of curtailment where appropriate, until a decline in ability to produce was anticipated. An estimated rate of decline was then applied to depletion of the reserves. If a decline trend has been established, this trend was used as the basis for estimating future production rates. For reserves not yet on production, sales were estimated to commence at an anticipated date furnished by Carrizo.

In general, we estimate that future gas production rates limited by allowables or marketing conditions will continue to be the same as the average rate for the latest available 12 months of actual production until such time that the well or wells are incapable of producing at this rate. The well or wells were then projected to decline at their decreasing delivery capacity rate. Our general policy on estimates of future gas production rates is adjusted when necessary to reflect actual gas market conditions in specific cases.

The future production rates from wells now on production may be more or less than estimated because of changes in market demand or allowables set by regulatory bodies. Wells or locations which are not currently producing may start producing earlier or later than anticipated in our estimates of their future production rates.

HYDROCARBON PRICES

Carrizo furnished us with hydrocarbon prices in effect at December 31, 2002 and with its forecasts of future prices which take into account SEC and Financial Accounting Standards Board (FASB) rules, current market prices, contract prices, and fixed and determinable price escalations where applicable.

In accordance with FASB Statement No. 69, December 31, 2002 market prices were determined using the daily oil price or daily gas sales price ("spot price") adjusted for oilfield or gas gathering hub and wellhead price differences (e.g. grade, transportation, gravity, sulfur and BS&W) as appropriate. Also in accordance with SEC and FASB specifications, changes in market prices subsequent to December 31, 2002 were not considered in this report.

For hydrocarbon products sold under contract, the contract price including fixed and determinable escalations, exclusive of inflation adjustments, was used until expiration of the contract. Upon contract expiration, the price was adjusted to the current market price for the area and held at this adjusted price to depletion of the reserves.

COSTS

Operating costs for the leases and wells in this report are based on the operating expense reports of Carrizo and include only those costs directly applicable to the leases or wells. When applicable, the operating costs include a portion of general and administrative costs allocated directly to the leases and wells under terms of operating agreements. No deduction was made for indirect costs such as general administration and overhead expenses, loan repayments, interest expenses, and exploration and development prepayments that are not charged directly to the leases or wells.

Development costs were furnished to us by Carrizo and are based on authorizations for expenditure for the proposed work or actual costs for similar projects. The estimated net cost of abandonment after salvage was included for properties where abandonment costs net of salvage are significant. At the request of Carrizo, their estimate of zero abandonment costs after salvage value for onshore properties was used in this report. Ryder Scott has not performed a detailed study of the abandonment costs nor the salvage value and makes no warranty for Carrizo's estimate.

Current costs were held constant throughout the life of the properties.

GENERAL

While it may reasonably be anticipated that the future prices received for the sale of production and the operating costs and other costs relating to such production may also increase or decrease from existing levels, such changes were, in accordance with rules adopted by the SEC, omitted from consideration in making this evaluation.

The estimates of reserves presented herein were based upon a detailed study of the properties in which Carrizo owns an interest; however, we have not made any field examination of the properties. No consideration was given in this report to potential environmental liabilities which may exist nor were any costs included for potential liability to restore and clean up damages, if any, caused by past operating practices. Carrizo has informed us that they have furnished us all of the accounts, records, geological and engineering data, and reports and other data required for this investigation. The ownership interests, prices, and other factual data furnished by Carrizo were accepted without independent verification. The estimates presented in this report are based on data available through December 2002.

Carrizo has assured us of their intent and ability to proceed with the development activities included in this report, and that they are not aware of any legal, regulatory or political obstacles that would significantly alter their plans.

Neither we nor any of our employees have any interest in the subject properties and neither the employment to make this study nor the compensation is contingent on our estimates of reserves and future income for the subject properties.

This report was prepared for the exclusive use and sole benefit of Carrizo Oil & Gas, Inc. The data, work papers, and maps used in this report are available for examination by authorized parties in our offices. Please contact us if we can be of further service.

Very truly yours,

RYDER SCOTT COMPANY, L.P.

/s/ MICHAEL F. STELL, P.E.

Michael F. Stell, P.E.
Vice President

MFS/sw

PETROLEUM RESERVES DEFINITIONS

SECURITIES AND EXCHANGE COMMISSION

INTRODUCTION

Reserves are those quantities of petroleum which are anticipated to be commercially recovered from known accumulations from a given date forward. All reserve estimates involve some degree of uncertainty. The uncertainty depends chiefly on the amount of reliable geologic and engineering data available at the time of the estimate and the interpretation of these data. The relative degree of uncertainty may be conveyed by placing reserves into one of two principal classifications, either proved or unproved. Unproved reserves are less certain to be recovered than proved reserves and may be further sub-classified as probable and possible reserves to denote progressively increasing uncertainty in their recoverability. It should be noted that Securities and Exchange Commission Regulation S-K prohibits the disclosure of estimated quantities of probable or possible reserves of oil and gas and any estimated value thereof in any documents publicly filed with the Commission.

Reserves estimates will generally be revised as additional geologic or engineering data become available or as economic conditions change. Reserves do not include quantities of petroleum being held in inventory, and may be reduced for usage or processing losses if required for financial reporting.

Reserves may be attributed to either natural energy or improved recovery methods. Improved recovery methods include all methods for supplementing natural energy or altering natural forces in the reservoir to increase ultimate recovery. Examples of such methods are pressure maintenance, cycling, waterflooding, thermal methods, chemical flooding, and the use of miscible and immiscible displacement fluids. Other improved recovery methods may be developed in the future as petroleum technology continues to evolve.

PROVED RESERVES (SEC DEFINITIONS)

Securities and Exchange Commission Regulation S-X Rule 4-10 paragraph (a) defines proved reserves as follows:

Proved Oil and Gas Reserves. Proved oil and gas reserves are the estimated quantities of crude oil, natural gas, and natural gas liquids which geological and engineering data demonstrate with reasonable certainty to be recoverable in future years from known reservoirs under existing economic and operating conditions, i.e., prices and costs as of the date the estimate is made. Prices include consideration of changes in existing prices provided only by contractual arrangements, but not on escalations based upon future conditions.

(i) Reservoirs are considered proved if economic producibility is supported by either actual production or conclusive formation test. The area of a reservoir considered proved includes:

(A) that portion delineated by drilling and defined by gas-oil and/or oil-water contacts, if any; and

(B) the immediately adjoining portions not yet drilled, but which can be reasonably judged as economically productive on the basis of available geological and engineering data. In the absence of information on fluid contacts, the lowest known structural occurrence of hydrocarbons controls the lower proved limit of the reservoir.

(ii) Reserves which can be produced economically through application of improved recovery techniques (such as fluid injection) are included in the "proved" classification when successful testing by a pilot project, or the operation of an installed program in the reservoir, provides support for the engineering analysis on which the project or program was based.

(iii) Estimates of proved reserves do not include the following:

(A) oil that may become available from known reservoirs but is classified separately as "indicated additional reserves";

(B) crude oil, natural gas, and natural gas liquids, the recovery of which is subject to reasonable doubt because of uncertainty as to geology, reservoir characteristics, or economic factors;

(C) crude oil, natural gas, and natural gas liquids, that may occur in undrilled prospects; and

(D) crude oil, natural gas, and natural gas liquids, that may be recovered from oil shales, coal, gilsonite and other such sources.

Proved Developed Oil and Gas Reserves. Proved developed oil and gas reserves are reserves that can be expected to be recovered through existing wells with existing equipment and operating methods. Additional oil and gas expected to be obtained through the application of fluid injection or other improved recovery techniques for supplementing the natural forces and mechanisms of primary recovery should be included as "proved developed reserves" only after testing by a pilot project or after the operation of an installed program has confirmed through production response that increased recovery will be achieved.

Proved Undeveloped Reserves. Proved undeveloped oil and gas reserves are reserves that are expected to be recovered from new wells on undrilled acreage, or from existing wells where a relatively major expenditure is required for recompletion. Reserves on undrilled acreage shall be limited to those drilling units offsetting productive units that are reasonably certain of production when drilled. Proved reserves for other undrilled units can be claimed only where it can be demonstrated with certainty that there is continuity of production from the existing productive formation. Under no circumstances should estimates for proved undeveloped reserves be attributable to any acreage for which an application of fluid injection or other improved recovery technique is contemplated, unless such techniques have been proved effective by actual tests in the area and in the same reservoir.

Certain Staff Accounting Bulletins published subsequent to the promulgation of Regulation S-X have dealt with matters relating to the application of financial accounting and disclosure rules for oil and gas producing activities. In particular, the following interpretations extracted from Staff Accounting Bulletins set forth the Commission staff's view on specific questions pertaining to proved oil and gas reserves.

Economic producibility of estimated proved reserves can be supported to the satisfaction of the Office of Engineering if geological and engineering data demonstrate with reasonable certainty that those reserves can be recovered in future years under existing economic and operating conditions. The relative importance of the many pieces of geological and engineering data which should be evaluated when classifying reserves cannot be identified in advance. In certain instances, proved reserves may be assigned to reservoirs on the basis of a combination of electrical and other type logs and core analyses which indicate the reservoirs are analogous to similar reservoirs in the same field which are producing or have demonstrated the ability to produce on a formation test. (extracted from SAB-35)

PETROLEUM RESERVES DEFINITIONS

In determining whether "proved undeveloped reserves" encompass acreage on which fluid injection (or other improved recovery technique) is contemplated, is it appropriate to distinguish between (i) fluid injection used for pressure maintenance during the early life of a field and (ii) fluid injection used to effect secondary recovery when a field is in the late stages of depletion? ... The Office of Engineering believes that the distinction identified in the above question may be appropriate in a few limited circumstances, such as in the case of certain fields in the North Sea. The staff will review estimates of proved reserves attributable to fluid injection in the light of the strength of the evidence presented by the registrant in support of a contention that enhanced recovery will be achieved. (extracted from SAB-35)

Companies should report reserves of natural gas liquids which are net to their leasehold interest, i.e., that portion recovered in a processing plant and allocated to the leasehold interest. It may be appropriate in the case of natural gas liquids not clearly attributable to leasehold interests ownership to follow instruction (b) of Item 2(b)(3) of Regulation S-K and report such reserves separately and describe the nature of the ownership. (extracted from SAB-35)

The staff believes that since coalbed methane gas can be recovered from coal in its natural and original location, it should be included in proved reserves, provided that it complies in all other respects with the definition of proved oil and gas reserves as specified in Rule 4-10(a)(2) including the requirement that methane production be economical at current prices, costs, (net of the tax credit) and existing operating conditions. (extracted from SAB-85)

Statements in Staff Accounting Bulletins are not rules or interpretations of the Commission nor are they published as bearing the Commission's official approval; they represent interpretations and practices followed by the Division of Corporation Finance and the Office of the Chief Accountant in administering the disclosure requirements of the Federal securities laws.

SUB-CATEGORIZATION OF DEVELOPED RESERVES (SPE/WPC DEFINITIONS)

In accordance with guidelines adopted by the Society of Petroleum Engineers (SPE) and the World Petroleum Congress (WPC), developed reserves may be sub-categorized as producing or non-producing.

Producing. Reserves sub-categorized as producing are expected to be recovered from completion intervals which are open and producing at the time of the estimate. Improved recovery reserves are considered producing only after the improved recovery project is in operation.

Non-Producing. Reserves sub-categorized as non-producing include shut-in and behind pipe reserves. Shut-in reserves are expected to be recovered from (1) completion intervals which are open at the time of the estimate but which have not started producing, (2) wells which were shut-in awaiting pipeline connections or as a result of a market interruption, or (3) wells not capable of production for mechanical reasons. Behind pipe reserves are expected to be recovered from zones in existing wells, which will require additional completion work or future recompletion prior to the start of production.

[FAIRCHILD AND WELLS, INC. LETTERHEAD]

February 20, 2002

Carrizo Oil & Gas, Inc.
14701 St. Mary's Lane, Suite 800
Houston, Texas 77079

RE: RESERVES EVALUATION TO THE INTERESTS OF CARRIZO OIL & GAS CORP. HEAVY OIL PROPERTIES, ANDERSON COUNTY, TEXAS

Gentlemen:

Fairchild and Wells, Inc. (FAW) has performed an engineering evaluation to estimate proved reserves and future cash flows from heavy oil (steamflood) properties to the interests of Carrizo Oil & Gas Corporation in Anderson County, Texas. This evaluation was authorized by Mr. S.P. Johnson IV, President of Carrizo Oil & Gas Corporation (Carrizo). Projections of the anticipated future annual oil production and future cash flows have also been prepared utilizing property development schedules provided by Carrizo. The reserves and future cash flows to the evaluated interests were based on economic parameters and operating conditions considered applicable and are pursuant to the financial reporting requirements of the Securities and Exchange Commission (SEC). December, 2002 hydrocarbon prices were used in the preparation of this report and current costs were held constant throughout the life of the properties.

The results of the study are summarized below.

SUMMARY

ESTIMATED PROVED RESERVES AND FUTURE CASH FLOWS

CAMP HILL FIELD ANDERSON COUNTY, TEXAS TO THE INTERESTS OF

CARRIZO OIL & GAS CORP.

EFFECTIVE 1/1/2003

	NET RESERVES MBBLS	FUTURE CASH FLOWS, BEFORE N (M$) UNDISCOUNTED	DISCOUNTED AT
Proved Producing			
18 Pattern Leases..........................	682.7	9,659.5	7,307.4
10 Pattern Lease...........................	67.2	957.4	810.7

Total Proved Producing........................	750.0	10,616.9	8,118.2
Proved Undeveloped			
Delaney A Lease............................	704.6	7,166.3	4,215.5
Temple Eastex C Lease.......................	1,359.5	15,880.2	8,938.6
Moore A Lease..........................	405.5	6,232.0	2,656.0
Moore B Lease..........................	93.8	1,202.8	606.5
Hanks Lease............................	137.1	1,731.6	866.5
C. Rosson..............................	2,161.6	23,796.5	8,229.8
Royall.................................	2,125.5	25,326.5	4,531.3
Total Proved Undeveloped......................	6,987.7	81,335.9	30,044.2
Total Proved..................................	7,737.6	91,952.8	38,162.4

Carrizo Oil & Gas, Inc.

February 20, 2003

FUTURE CASH FLOW -- TOTAL PROJECT BY YEAR
(AFTER NET PROFITS INTEREST)

	FUTURE CASH FLOWS AFTER NPI (	
YEAR	UNDISCOUNTED	DISCOUNTED AT
2003..	116.2	110.8
2004..	76.9	66.6
2005..	5,358.9	4,222.7
2006..	4,895.9	3,507.2
2007..	4,793.8	3,121.8
2008..	5,424.5	3,211.5
2009..	5,593.9	3,010.7
2010..	6,517.2	3,188.7
2011..	4,986.3	2,217.9
2012..	4,361.1	1,763.5
2013..	5,229.8	1,922.5
2014..	7,265.8	2,428.1
2015..	4,907.8	1,491.0
2016..	4,008.7	1,107.1
2017..	2,205.4	553.7
2018..	2,949.1	673.1
2019..	2,375.1	492.8
2020..	2,441.4	460.5
2021..	2,735.7	469.1
2022..	3,260.7	508.3
2023..	2,211.5	313.4
2024..	2,166.2	279.1
2025..	2,356.0	276.0
2026..	1,026.0	109.3
2027..	197.9	19.2
TOTAL...	87,461.9	35,524.8

The estimated reserves and future cash flows shown in this report are for proved developed producing and proved undeveloped reserves. Our estimates do not include any value which might be attributed to interests in undeveloped acreage beyond those tracts for which reserves have been assigned.

In performance of this evaluation, we have relied upon information furnished by Carrizo with respect to property interests owned, production from such properties, current costs of operation and development, current prices for production, agreements relating to current and future operations and sale of production. With respect to the technical files supplied by Carrizo, we have accepted the authenticity and sufficiency of the data contained therein.

Future cash flow is presented after deducting production taxes and after deducting future capital costs and operating expenses, but before consideration of Federal income taxes. The future cash flow has been discounted at an annual rate of 10 percent to determine its "present worth." The present worth is shown to indicate the effect of time on the value of money and should not be

construed as being the fair market value of the properties Our estimates of future revenue do not include any salvage value for the lease and well equipment Fairchild and Wells, Inc. expresses no opinion as to the fair market value of the evaluated properties.

The reserves included in this report are estimates only and should not be construed as being exact quantities. They may or may not be actually recovered, and if recovered, the revenues therefrom and the actual costs related thereto could be more or less than the estimated amounts. Because of governmental policies and uncertainties of supply and demand, the actual sales rates and the prices actually received for the reserves along with the costs incurred in recovering such reserves may vary from those assumptions included in this report. Also, estimates of reserves may increase or decrease as a result of future operations.

In evaluating the information at our disposal concerning this report, we have excluded from our consideration all matters as to which legal or accounting, rather than engineering, interpretation may be controlling. As in all aspects of oil and gas evaluation, there are uncertainties inherent in the interpretation of engineering data and, therefore, our conclusions necessarily represent only informed professional judgments.

The titles to the properties have not been examined by Fairchild and Wells, Inc. nor has the actual degree or type of interest owned been independently confirmed. We are independent petroleum engineers and geologists; we do not own an interest in these properties and are not employed on a contingent basis. Basic geologic and field performance data together with our engineering work sheets are maintained on file in our office and are available for review.

It has been a pleasure to serve you by preparing this engineering evaluation.

Yours very truly,

FAIRCHILD AND WELLS, INC.

/s/ JAMES FAIRCHILD

James Fairchild
President

A-11

March 28, 2003

CCBM, Inc.
14701 St. Mary's Lane, Suite 800
Houston, Texas 77079

Gentlemen:

At your request, we have prepared an estimate of the reserves, future production, and income attributable to certain leasehold interests of CCBM, Inc. (CCBM) as of December 31, 2002. The subject properties are located in the Bobcat Field, Campbell County, Wyoming. The income data were estimated using the Securities and Exchange Commission (SEC) requirements for future price and cost parameters.

The estimated reserves and future income amounts presented in this report are related to hydrocarbon prices. Hydrocarbon prices in effect at December 31, 2002 were used in the preparation of this report as required by SEC rules; however, actual future prices may vary significantly from December 31, 2002 prices. Therefore, volumes of reserves actually recovered and amounts of income actually received may differ significantly from the estimated quantities presented in this report. The results of this study are summarized below.

SEC PARAMETERS
ESTIMATED NET RESERVES AND INCOME DATA
CERTAIN LEASEHOLD INTERESTS OF
CCBM, INC.
BOBCAT FIELD
AS OF DECEMBER 31, 2002

	PROVED		
	DEVELOPED PRODUCING	UNDEVELOPED	TOTAL PROVED
NET REMAINING RESERVES			
Gas -- MMCF	490	96	586
INCOME DATA			
Future Gross Revenue	$1,394,130	$273,082	$1,667,212
Deductions	473,728	142,180	615,908
Future Net Income (FNI)	$ 920,402	$130,902	$1,051,304
Discounted FNI @ 10%	$ 793,481	$ 94,947	$ 888,428

All gas volumes are sales gas expressed in millions of cubic feet (MMCF) at the official temperature and pressure bases of Wyoming, which are 60 degrees and 14.73 psia.

The future gross revenue is after the deduction of production taxes. The deductions comprise the normal direct costs of operating the wells, ad valorem taxes, completion costs, and development costs. The future net income is before the deduction of state and federal income taxes and general administrative overhead, and has not been adjusted for outstanding loans that may exist nor does it include any adjustment for cash on hand or undistributed income. No attempt was made to quantify or otherwise account for any accumulated gas production imbalances that may exist. Gas reserves account for 100 percent of total future gross revenue from proved reserves.

RESERVES INCLUDED IN THIS REPORT

The proved reserves included herein conform to the definition as set forth in the Securities and Exchange Commission's Regulation S-X Part 210.4-10 (a) as clarified by subsequent Commission Staff Accounting Bulletins. The definition of proved reserves is included in the section entitled "Petroleum Reserves Definitions" which is attached with this report.

Because of the direct relationship between volumes of proved undeveloped reserves and development plans, we include in the proved undeveloped category only reserves assigned to undeveloped locations that we have been assured will definitely be drilled.

The various reserve status categories are in the section entitled "Petroleum Reserves Definitions" which is attached with this report.

ESTIMATES OF RESERVES

Producing reserves were estimated based on performance analysis and volumetric calculations. Undeveloped reserves were based on analogy to offset wells. All of the reserves are based on primary recovery from coal seams.

The reserves included in this report are estimates only and should not be construed as being exact quantities. They may or may not be actually recovered, and if recovered, the revenues therefrom and the actual costs related thereto could be more or less than the estimated amounts. Moreover, estimates of reserves may increase or decrease as a result of future operations.

FUTURE PRODUCTION RATES

Initial production rates are based on the current producing rates for those wells now on production. Test data and other related information were used to estimate the anticipated initial production rates for those wells or locations that are not currently producing. If no production decline trend had been established, future production rates were inclined during the dewatering phase or held constant, as appropriate, until a decline in ability to produce was anticipated. An estimated rate of decline was then applied to depletion of the reserves. If a decline trend had been established, this trend was used as the basis for estimating future production rates. For reserves not yet on production, sales were estimated to commence at an anticipated date furnished by CCBM.

The future production rates from wells now on production may be more or less than estimated because of changes in market demand or allowables set by regulatory bodies. Wells or locations that are not currently producing may start producing earlier or later than anticipated in our estimates of their future production rates.

HYDROCARBON PRICES

In accordance with FASB Statement No. 69, December 31, 2002 market prices were determined using the daily gas sales price ("spot price") adjusted for gas gathering hub and wellhead price differences (e.g. grade, transportation, gravity, sulfur and BS&W) as appropriate. Also in accordance with SEC and FASB specifications, changes in market prices subsequent to December 31, 2002 were not considered in this report.

The December 31, 2002 gas price of $3.00 per MCF was used in this report, which was based on a Henry Hub benchmark price of $4.75 per MMBTU, less a historical differential of $1.75 per MMBTU, times 1000 BTU per cubic foot. This December 31, 2002 gas price was held constant throughout the life of the properties.

The effects of derivative instruments designated as price hedges of oil and gas quantities were not considered or included in this report.

COSTS

Because the historical operating cost for the subject properties are still affected by non-reoccurring start-up cost, operating costs for the leases and wells in this report were estimated and provided by CCBM. Operating costs were based on the operating expense reports of CCBM and include only those costs directly applicable to the leases or wells. When applicable, the operating costs include a portion of general and administrative costs allocated directly to the leases and wells under terms of operating agreements. No deduction was made for indirect costs such as general administration and overhead expenses, loan repayments, interest expenses, and exploration and development prepayments that are not charged directly to the leases or wells.

Development costs were furnished to us by CCBM and are based on authorizations for expenditure for the proposed work or actual costs for similar projects. At the request of CCBM, their estimate of zero abandonment costs after salvage value for these onshore properties was used in this report. Ryder Scott has not performed a detailed study of the abandonment costs or the salvage value and makes no warranty for CCBM's estimate.

Current costs were held constant throughout the life of the properties.

GENERAL

While it may reasonably be anticipated that the future prices received for the sale of production and the operating costs and other costs relating to such production may also increase or decrease from existing levels, such changes were, in accordance with rules adopted by the SEC, omitted from consideration in making this evaluation.

The estimates of reserves presented herein were based upon a detailed study of the properties in which CCBM owns an interest; however, we have not made any field examination of the properties. No consideration was given in this report to potential environmental liabilities that may exist nor were any costs included for potential liability to restore and clean up damages, if any, caused by past operating practices. CCBM has informed us that they have furnished us all of the accounts, records, geological and engineering data, and reports and other data required for this investigation. The ownership interests, prices, and other factual data furnished by CCBM were accepted without independent verification. The estimates presented in this report are based on data available through December 2002.

CCBM has assured us of their intent and ability to proceed with the development activities included in this report, and that they are not aware of any legal, regulatory or political obstacles that would significantly alter their plans.

Neither we nor any of our employees have any interest in the subject properties and neither the employment to make this study nor the compensation is contingent on our estimates of reserves and future income for the subject properties.

This report was prepared for the exclusive use and sole benefit of CCBM, Inc. The data, work papers, and maps used in this report are available for examination by authorized parties in our offices. Please contact us if we can be of further service.

Very truly yours,

RYDER SCOTT COMPANY, L.P.

/s/ JOSEPH E. BLANKENSHIP, P.E.

Joseph E. Blankenship, P.E.
Senior Vice President

JEB/sw

PETROLEUM RESERVES DEFINITIONS

SECURITIES AND EXCHANGE COMMISSION

INTRODUCTION

Reserves are those quantities of petroleum which are anticipated to be commercially recovered from known accumulations from a given date forward. All reserve estimates involve some degree of uncertainty. The uncertainty depends chiefly on the amount of reliable geologic and engineering data available at the time of the estimate and the interpretation of these data. The relative degree of uncertainty may be conveyed by placing reserves into one of two principal classifications, either proved or unproved. Unproved reserves are less certain to be recovered than proved reserves and may be further sub-classified as probable and possible reserves to denote progressively increasing uncertainty in their recoverability. It should be noted that Securities and Exchange Commission Regulation S-K prohibits the disclosure of estimated quantities of probable or possible reserves of oil and gas and any estimated value thereof in any documents publicly filed with the Commission.

Reserves estimates will generally be revised as additional geologic or engineering data become available or as economic conditions change. Reserves do not include quantities of petroleum being held in inventory, and may be reduced for usage or processing losses if required for financial reporting.

Reserves may be attributed to either natural energy or improved recovery methods. Improved recovery methods include all methods for supplementing natural energy or altering natural forces in the reservoir to increase ultimate recovery. Examples of such methods are pressure maintenance, cycling, waterflooding, thermal methods, chemical flooding, and the use of miscible and immiscible displacement fluids. Other improved recovery methods may be developed in the future as petroleum technology continues to evolve.

PROVED RESERVES (SEC DEFINITIONS)

Securities and Exchange Commission Regulation S-X Rule 4-10 paragraph (a) defines proved reserves as follows:

Proved Oil and Gas Reserves. Proved oil and gas reserves are the estimated quantities of crude oil, natural gas, and natural gas liquids which geological and engineering data demonstrate with reasonable certainty to be recoverable in future years from known reservoirs under existing economic and operating conditions, i.e., prices and costs as of the date the estimate is made. Prices include consideration of changes in existing prices provided only by contractual arrangements, but not on escalations based upon future conditions.

(i) Reservoirs are considered proved if economic producibility is supported by either actual production or conclusive formation test. The area of a reservoir considered proved includes:

(A) that portion delineated by drilling and defined by gas-oil and/or oil-water contacts, if any; and

(B) the immediately adjoining portions not yet drilled, but which can be reasonably judged as economically productive on the basis of available geological and engineering data. In the absence of information on fluid contacts, the lowest known structural occurrence of hydrocarbons controls the lower proved limit of the reservoir.

PETROLEUM RESERVES DEFINITIONS

Page 2

(ii) Reserves which can be produced economically through application of improved recovery techniques (such as fluid injection) are included in the "proved" classification when successful testing by a pilot project, or the operation of an installed program in the reservoir, provides support for the engineering analysis on which the project or program was based.

(iii) Estimates of proved reserves do not include the following:

(A) oil that may become available from known reservoirs but is classified separately as "indicated additional reserves";

(B) crude oil, natural gas, and natural gas liquids, the recovery of which is subject to reasonable doubt because of uncertainty as to geology, reservoir characteristics, or economic factors;

(C) crude oil, natural gas, and natural gas liquids, that may occur in undrilled prospects; and

(D) crude oil, natural gas, and natural gas liquids, that may be recovered from oil shales, coal, gilsonite and other such sources.

Proved Developed Oil and Gas Reserves. Proved developed oil and gas reserves are reserves that can be expected to be recovered through existing wells with existing equipment and operating methods. Additional oil and gas expected to be obtained through the application of fluid injection or other improved recovery techniques for supplementing the natural forces and mechanisms of primary recovery should be included as "proved developed reserves" only after testing by a pilot project or after the operation of an installed program has confirmed through production response that increased recovery will be achieved.

Proved Undeveloped Reserves. Proved undeveloped oil and gas reserves are reserves that are expected to be recovered from new wells on undrilled acreage, or from existing wells where a relatively major expenditure is required for recompletion. Reserves on undrilled acreage shall be limited to those drilling units offsetting productive units that are reasonably certain of production when drilled. Proved reserves for other undrilled units can be claimed only where it can be demonstrated with certainty that there is continuity of production from the existing productive formation. Under no circumstances should estimates for proved undeveloped reserves be attributable to any acreage for which an application of fluid injection or other improved recovery technique is contemplated, unless such techniques have been proved effective by actual tests in the area and in the same reservoir.

Certain Staff Accounting Bulletins published subsequent to the promulgation of Regulation S-X have dealt with matters relating to the application of financial accounting and disclosure rules for oil and gas producing activities. In particular, the following interpretations extracted from Staff Accounting Bulletins set forth the Commission staff's view on specific questions pertaining to proved oil and gas reserves.

Economic producibility of estimated proved reserves can be supported to the satisfaction of the Office of Engineering if geological and engineering data demonstrate with reasonable certainty that those reserves can be recovered in future years under existing economic and operating conditions. The relative importance of the many pieces of geological and engineering data which should be evaluated when classifying reserves cannot be identified in advance. In certain instances, proved reserves may be assigned to reservoirs on the basis of a combination of electrical and other type logs and core analyses which indicate the reservoirs are analogous to similar reservoirs in the same field which are producing or have demonstrated the ability to produce on a formation test. (extracted from SAB-35)

In determining whether "proved undeveloped reserves" encompass acreage on which fluid injection (or other improved recovery technique) is contemplated, is it appropriate to distinguish between (i) fluid injection used for pressure maintenance during the early life of a field and (ii) fluid injection used to effect secondary recovery when a field is in the late stages of depletion? ... The Office of Engineering believes that the distinction identified in the above question may be appropriate in a few limited circumstances, such as in the case of certain fields in the North Sea. The staff will review estimates of proved reserves attributable to fluid injection in the light of the strength of the evidence presented by the registrant in support of a contention that enhanced recovery will be achieved. (extracted from SAB-35)

Companies should report reserves of natural gas liquids which are net to their leasehold interest, i.e., that portion recovered in a processing plant and allocated to the leasehold interest. It may be appropriate in the case of natural gas liquids not clearly attributable to leasehold interests ownership to follow instruction (b) of Item 2(b)(3) of Regulation S-K and report such reserves separately and describe the nature of the ownership. (extracted from SAB-35)

THE STAFF BELIEVES THAT SINCE COALBED METHANE GAS CAN BE RECOVERED FROM COAL IN ITS NATURAL AND ORIGINAL LOCATION, IT SHOULD BE INCLUDED IN PROVED RESERVES, PROVIDED THAT IT COMPLIES IN ALL OTHER RESPECTS WITH THE DEFINITION OF PROVED OIL AND GAS RESERVES AS SPECIFIED IN RULE 4-10(a)(2) INCLUDING THE REQUIREMENT THAT METHANE PRODUCTION BE ECONOMICAL AT CURRENT PRICES, COSTS, (NET OF THE TAX CREDIT) AND EXISTING OPERATING CONDITIONS. (EXTRACTED FROM SAB-85)

Statements in Staff Accounting Bulletins are not rules or interpretations of the Commission nor are they published as bearing the Commission's official approval; they represent interpretations and practices followed by the Division of Corporation Finance and the Office of the Chief Accountant in administering the disclosure requirements of the Federal securities laws.

SUB-CATEGORIZATION OF DEVELOPED RESERVES (SPE/WPC DEFINITIONS)

In accordance with guidelines adopted by the Society of Petroleum Engineers (SPE) and the World Petroleum Congress (WPC), developed reserves may be sub-categorized as producing or non-producing.

Producing. Reserves sub-categorized as producing are expected to be recovered from completion intervals which are open and producing at the time of the estimate. Improved recovery reserves are considered producing only after the improved recovery project is in operation.

Non-Producing. Reserves sub-categorized as non-producing include shut-in and behind pipe reserves. Shut-in reserves are expected to be recovered from (1) completion intervals which are open at the time of the estimate but which have not started producing, (2) wells which were shut-in awaiting pipeline connections or as a result of a market interruption, or (3) wells not capable of production for mechanical reasons. Behind pipe reserves are expected to be recovered from zones in existing wells, which will require additional completion work or future recompletion prior to the start of production.

(CARRIZO OIL & GAS, INC. LOGO)

5,700,000 SHARES

COMMON STOCK

PROSPECTUS

, 2004

CIBC WORLD MARKETS
FIRST ALBANY CAPITAL
HIBERNIA SOUTHCOAST CAPITAL
JOHNSON RICE & COMPANY L.L.C.

YOU SHOULD RELY ONLY ON THE INFORMATION CONTAINED OR INCORPORATED BY REFERENCE IN THIS PROSPECTUS. NO DEALER, SALESPERSON OR OTHER PERSON IS AUTHORIZED TO GIVE INFORMATION THAT IS NOT CONTAINED IN THIS PROSPECTUS. THIS PROSPECTUS IS NOT AN OFFER TO SELL NOR IS IT SEEKING AN OFFER TO BUY THESE SECURITIES IN ANY JURISDICTION WHERE THE OFFER OR SALE IS NOT PERMITTED. THE INFORMATION CONTAINED IN THIS PROSPECTUS IS CORRECT ONLY AS OF THE DATE OF THIS PROSPECTUS, REGARDLESS OF THE TIME OF THE DELIVERY OF THIS PROSPECTUS OR ANY SALE OF THESE SECURITIES.

PART II

INFORMATION NOT REQUIRED IN PROSPECTUS

ITEM 14. OTHER EXPENSES OF ISSUANCE AND DISTRIBUTION.

The following table sets forth the costs and expenses, other than the underwriters' discount and commissions, payable by us in connection with the sale of common stock being registered. All amounts are estimates except the SEC registration fee.

SEC registration fee......................................	$
NASD filing fee...	

Nasdaq National Market listing fee........................	22,500
Printing expenses...	50,000
Legal fees and expenses...................................	
Accounting fees and expenses..............................	
Miscellaneous expenses....................................	
Total...	$

ITEM 15. INDEMNIFICATION OF DIRECTORS AND OFFICERS.

Article 2.02-1 of the Texas Business Corporation Act provides that a corporation may indemnify any director or officer who was, is or is threatened to be made a named defendant or respondent in a proceeding because he is or was a director or officer, provided that the director or officer (i) conducted himself in good faith, (ii) reasonably believed (a) in the case of conduct in his official capacity, that his conduct was in the corporation's best interests or (b) in all other cases, that his conduct was at least not opposed to the corporation's best interests and (iii) in the case of any criminal proceeding, had no reasonable cause to believe his conduct was unlawful. Subject to certain exceptions, a director or officer may not be indemnified if the person is found liable to the corporation or if the person is found liable on the basis that he improperly received a personal benefit. Under Texas law, the corporation may pay or reimburse, in advance of a final disposition of the proceeding, reasonable expenses incurred by a director or officer after the corporation receives a written affirmation by the director or officer of his good faith belief that he has met the standard of conduct necessary for indemnification and a written undertaking by or on behalf of the director or officer to repay the amount if it is ultimately determined that the director or officer is not entitled to indemnification by the corporation. Texas law requires a corporation to indemnify an officer or director against reasonable expenses incurred in connection with the proceeding in which he is named defendant or respondent because he is or was a director or officer if he is wholly successful in defense of the proceeding.

Texas law also permits a corporation to purchase and maintain insurance or another arrangement on behalf of any person who is or was a director or officer against any liability asserted against him and incurred by him in such a capacity or arising out of his status as such a person, whether or not the corporation would have the power to indemnify him against that liability under Article 2.02-1.

Our bylaws provide for the indemnification of our officers and directors, and the advancement to them of expenses in connection with proceedings and claims, to the fullest extent permitted by the Texas Business Corporation Act. We also have entered into indemnification agreements with each of our directors and certain of our officers that contractually provide for indemnification and expense advancement and include related provisions meant to facilitate the indemnitee's receipt of such benefits. These provisions, among other things:

- specify the method of determining entitlement to indemnification and the selection of independent counsel that will in some cases make such determination;

- specify certain time periods by which certain payments or determinations must be made and actions must be taken; and

- establish certain presumptions in favor of an indemnitee.

The benefits of certain of these provisions are available to an indemnitee only if there has been a change in control (as defined).

In addition, we may purchase directors' and officers' liability insurance policies for our directors and officers in the future. The bylaws and these agreements with directors and officers provide for indemnification for amounts:

- in respect of the deductibles for such insurance policies;

- that exceed the liability limits of such insurance policies; and

- that are available, were available or become available to us but that our officers or directors determine is inadvisable for us to purchase, given the cost involved.

Such indemnification may be made even though our directors and officers would not otherwise be entitled to indemnification under other provisions of the bylaws or these agreements.

This discussion of Article 2.02-1 of the Texas Business Corporation Act and of our bylaws is not intended to be exhaustive and is qualified in its entirety by reference to the statute and our bylaws. We also refer you to the form of the Underwriting Agreement, filed as Exhibit 1.1 to this registration statement, which contains provisions for indemnification of us, our directors, our officers and any controlling persons by the underwriters against certain liabilities for information furnished by the underwriters.

ITEM 16. EXHIBITS.

The exhibits listed in the accompanying Index to Exhibits are filed or incorporated by reference as part of this registration statement.

ITEM 17. UNDERTAKINGS.

(H) REQUEST FOR ACCELERATION OF EFFECTIVE DATE

Insofar as indemnification for liabilities arising under the Securities Act of 1933 may be permitted to our directors, officers and controlling persons pursuant to the foregoing provisions, or otherwise, we have been advised that in the opinion of the Securities and Exchange Commission, such indemnification is against public policy as expressed in the Act and is, therefore, unenforceable. In the event that a claim for indemnification against such liabilities (other than the payment by us for expenses incurred or paid by a director, officer or controlling person of us in the successful defense of any action, suit or proceeding) is asserted by such director, officer or controlling person in connection with the securities being registered, we will, unless in the opinion of its counsel the matter has been settled by controlling precedent, submit to a court of appropriate jurisdiction the question whether such indemnification by it is against public policy as expressed in the Act and will be governed by the final adjudication of such issue.

(I) REGISTRATION STATEMENT PERMITTED BY RULE 430A UNDER THE SECURITIES ACT OF 1933

The undersigned Registrant hereby undertakes that:

For the purposes of determining liability under the Securities Act of 1933, the information omitted from the form of prospectus filed as part of this registration statement in reliance upon Rule 430A and contained in a form of prospectus filed by the Registrant pursuant to Rule 424(b)(1) or (4) or Rule

497(h) under the Securities Act shall be deemed to be a part of this registration statement as of the time it was declared effective.

For the purposes of determining any liability under the Securities Act of 1933, each post-effective amendment that contains a form of prospectus shall be deemed to be a new registration statement relating to the securities offered therein, and the offering of such securities at that time shall be deemed to be the initial bona fide offering thereof.

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SIGNATURES

Pursuant to the requirements of the Securities Act of 1933, the registrant certifies that it has reasonable grounds to believe that it meets all of the requirements for filing on Form S-2 and has duly caused this Registration Statement to be signed on its behalf by the undersigned, thereunto duly authorized, in the City of Houston, Texas on January 15, 2004.

CARRIZO OIL & GAS, INC.

By: /s/ S.P. JOHNSON IV

S.P. Johnson IV
President and Chief Executive Officer

Pursuant to the requirements of the Securities Act of 1933, this Amendment No. 1 to the Registration Statement has been signed by the following persons in the capacities and on the dates indicated.

SIGNATURE	TITLE	DATE
/s/ S.P. JOHNSON IV S.P. Johnson IV	President, Chief Executive Officer and Director (Principal Executive Officer)	January 15, 2004
/s/ PAUL F. BOLING Paul F. Boling	Chief Financial Officer, Vice President, Secretary and Treasurer (Principal Financial and Accounting Officer)	January 15, 2004
* Steven A. Webster	Chairman	January 15, 2004
*	Director	January 15, 2004

Christopher C. Behrens

*	Director	January 15, 2004
Douglas A. P. Hamilton		
*	Director	January 15, 2004
Paul B. Loyd, Jr.		
*	Director	January 15, 2004
Bryan R. Martin		
*	Director	January 15, 2004
F. Gardner Parker		
*	Director	January 15, 2004
Frank A. Wojtek		

*By: /s/ PAUL F. BOLING

Paul F. Boling
Attorney-in-fact

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INDEX TO EXHIBITS

EXHIBIT NUMBER		DESCRIPTION
**1.1	--	Form of Underwriting Agreement
2.1	--	Combination Agreement by and among Carrizo Oil & Gas, Inc. (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 June 6, 1997 (incorporated by reference to Exhibit 2.1 to the Company's Registration Statement on Form S-1 (Registration No. 333-29187)).
4.1	--	Credit Agreement dated as of May 24, 2002 by and among the Company, CCBM, Inc. and Hibernia National Bank (incorporated by reference to Exhibit 4.1 to the Company's Quarterly Report on Form 10-Q for the quarter ended June 30, 2002).
4.2	--	Revolving Note by and between the Company and Hibernia National Bank dated May 24, 2002 (incorporated by reference to Exhibit 4.2 to the Company's Quarterly Report on Form

		10-Q for the quarter ended June 30, 2002).
4.3	--	Commercial Guarantee by and between CCBM, Inc. and Hibernia National Bank dated May 24, 2002 (incorporated by reference to Exhibit 4.3 to the Company's Quarterly Report on Form 10-Q for the quarter ended June 30, 2002).
4.4	--	Stock Pledge and Security Agreement by and between the Company and Hibernia National Bank dated May 24, 2002 (incorporated by reference to Exhibit 4.4 to the Company's Quarterly Report on Form 10-Q for the quarter ended June 30, 2002).
4.5	--	First Amendment to Credit Agreement dated July 9, 2002 to the Credit Agreement by and between the Company and Hibernia National Bank dated May 24, 2002 (incorporated by reference to Exhibit 4.5 to the Company's Quarterly Report on Form 10-Q for the quarter ended June 30, 2002).
4.6	--	Amended and Restated Credit Agreement dated as of December 12, 2002 by and among the Company, CCBM, Inc. and Hibernia National Bank (incorporated by reference to Exhibit 4.6 to the Company's 10-K for the year ended December 31, 2002).
4.7	--	Letter Agreement Regarding Participation in the Company's 2001 Seismic and Acreage Program, dated May 1, 2001 (incorporated by reference to Exhibit 4.1 to the Company's Quarterly Report on Form 10-Q for the quarter ended June 30, 2001).
4.8	--	Amendment No. 1 to the Letter Agreement Regarding Participation in the Company's 2001 Seismic and Acreage Program, dated June 1, 2001 (incorporated by reference to Exhibit 4.2 to the Company's Quarterly Report on Form 10-Q for the quarter ended June 30, 2001).
4.9	--	Promissory Note payable to Rocky Mountain Gas, Inc. by CCBM, Inc. (incorporated by reference to Exhibit 4.3 to the Company's Quarterly Report on Form 10-Q for the quarter ended June 30, 2001).
4.10	--	Form of Certificate representing Common Stock (incorporated by reference to Exhibit No. 4.1 to the Company's Registration Statement on Form S-1 (Registration No. 333-29187)).
4.11	--	The Company is a party to several debt instruments under which the total amount of securities authorized does not exceed 10% of the total assets of the Company and its subsidiaries on a consolidated basis. Pursuant to paragraph 4(iii)(A) of Item 601(b) of Regulation S-K, the Company agrees to furnish a copy of such instruments to the Commission upon request.
**5.1	--	Opinion of Baker Botts L.L.P.
10.1	--	Amended and Restated Incentive Plan of the Company effective as of February 17, 2000 (incorporated by reference to Exhibit 10.3 to the Company's Quarterly Report on Form 10-Q for the quarter ended June 30, 2000).
10.2	--	Amendment No. 1 to the Amended and Restated Incentive Plan of the Company (incorporated by reference to Exhibit 10.1 to the Company's Quarterly Report on Form 10-Q for the quarter ended June 30, 2002).

EXHIBIT NUMBER		DESCRIPTION

10.3	--	Amendment to the Amended and Restated Incentive Plan of the Company (incorporated by reference to Exhibit 10.3 to the Company's Report on Form 10-K for the year ended December 31, 2002).
10.4	--	Employment Agreement between the Company and S.P. Johnson IV (incorporated by reference to Exhibit 10.2 to the Company's Registration Statement on Form S-1 (Registration No. 333-29187)).
10.5	--	Employment Agreement between the Company and Frank A. Wojtek (incorporated by reference to Exhibit 10.3 to the Company's Registration Statement on Form S-1 (Registration No. 333-29187)).
10.6	--	Employment Agreement between the Company and Kendall A. Trahan (incorporated by reference to Exhibit 10.4 to the Company's Registration Statement on Form S-1 (Registration No. 333-29187)).
10.7	--	Employment Agreement between the Company and Jeremy T. Greene (incorporated by reference to Exhibit 10.1 to the Company's Quarterly Report on Form 10-Q for the quarter ended June 30, 2002).
*10.8	--	Employment Agreement between the Company and J. Bradley Fisher.
*10.9	--	Employment Agreement between the Company and Paul F. Boling.
10.10	--	Form of Amendment to Executive Officer Employment Agreement (incorporated by reference to Exhibit 99.3 to the Company's Current Report on Form 8-K dated January 8, 1998).
10.11	--	Form of Amendment to Executive Officer Employment Agreement (incorporated by reference to Exhibit 99.7 to the Company's Current Report on Form 8-K dated December 15, 1999).
10.12	--	Form of Amendment to Executive Officer Employment Agreement (incorporated by reference to Exhibit 99.7 to the Company's Current Report on Form 8-K dated February 20, 2002).
10.13	--	Indemnification Agreement between the Company and each of its directors and executive officers (incorporated by reference to Exhibit 10.6 to the Company's Annual Report on Form 10-K for the year ended December 31, 1998).
10.14	--	Form of Amendment to Director Indemnification Agreement (incorporated by reference to Exhibit 99.8 to the Company's Current Report on Form 8-K dated December 15, 1999).
10.15	--	Form of Amendment to Director Indemnification Agreement (incorporated by reference to Exhibit 99.8 to the Company's Current Report on Form 8-K dated February 20, 2002).
10.16	--	S Corporation Tax Allocation, Payment and Indemnification Agreement among the Company and Messrs. Loyd, Webster, Johnson, Hamilton and Wojtek (incorporated by reference to Exhibit 10.8 to the Company's Registration Statement on Form S-1 (Registration No. 333-29187)).
10.17	--	S Corporation Tax Allocation, Payment and Indemnification Agreement among Carrizo Production, Inc. and Messrs. Loyd, Webster, Johnson, Hamilton and Wojtek (incorporated by reference to Exhibit 10.9 to the Company's Registration Statement on Form S-1 (Registration No. 333-29187)).
10.18	--	Amended Enron Warrant Certificates (incorporated by reference to Exhibit 4.1 to the Company's Current Report on Form 8-K dated December 15, 1999).
10.19	--	Securities Purchase Agreement dated December 15, 1999 among the Company, CB Capital Investors, L.P., Mellon Ventures, L.P. and Messrs. Loyd, Hamilton and Webster (incorporated by reference to Exhibit 99.1 to the Company's Current Report on Form 8-K dated December 15, 1999).

10.20	--	Shareholders Agreement dated December 15, 1999 among the Company, CB Capital Investors, L.P., Mellon Ventures, L.P., Messrs. Loyd, Hamilton, Webster, Johnson and Wojtek and DAPHAM Partnership, L.P. (incorporated by reference to Exhibit 99.2 to the Company's Current Report on Form 8-K dated December 15, 1999).

EXHIBIT NUMBER		DESCRIPTION
10.21	--	Warrant Agreement dated December 15, 1999 among the Company, CB Capital Investors, L.P., Mellon Ventures, L.P. and Messrs. Loyd, Hamilton and Webster (incorporated by reference to Exhibit 99.3 to the Company's Current Report on Form 8-K dated December 15, 1999).
10.22	--	Registration Rights Agreement dated December 15, 1999 among the Company, CB Capital Investors, L.P. and Mellon Ventures, L.P. (incorporated by reference to Exhibit 99.4 to the Company's Current Report on Form 8- K dated December 15, 1999).
10.23	--	Amended and Restated Registration Rights Agreement dated December 15, 1999 among the Company, Messrs. Loyd, Hamilton, Webster, Johnson and Wojtek and DAPHAM Partnership, L.P. (incorporated by reference to Exhibit 99.5 to the Company's Current Report on Form 8-K dated December 15, 1999).
10.24	--	Compliance Sideletter dated December 15, 1999 among the Company, CB Capital Investors, L.P. and Mellon Ventures, L.P. (incorporated by reference to Exhibit 99.6 to the Company's Current Report on Form 8-K dated December 15, 1999).
10.25	--	Purchase and Sale Agreement by and between Rocky Mountain Gas, Inc. and CCBM, Inc., dated June 29, 2001 (incorporated by reference to Exhibit 10.1 to the Company's Quarterly Report on Form 10-Q for the quarter ended June 30, 2001).
10.26	--	Securities Purchase Agreement dated February 20, 2002 among the Company, Mellon Ventures, L.P. and Steven A. Webster (incorporated by reference to Exhibit 99.1 to the Company's Current Report on Form 8-K dated February 20, 2002).
10.27	--	Shareholders' Agreement dated February 20, 2002 among the Company, Mellon Ventures, L.P. Messrs. Loyd, Hamilton, Webster, Johnson and Wojtek and DAPHAM Partnership, L.P. (incorporated by reference to Exhibit 99.3 to the Company's Current Report on Form 8-K dated February 20, 2002).
10.28	--	Warrant Agreement dated February 20, 2002 among the Company, Mellon Ventures, L.P. and Mr. Webster (including Warrant Certificate) (incorporated by reference to Exhibit 99.4 to the Company's Current Report on Form 8-K dated February 20, 2002).
10.29	--	Registration Rights Agreement dated February 20, 2002 among the Company, Mellon Ventures, L.P. and Mr. Webster (incorporated by reference to Exhibit 99.5 to the Company's Current Report on Form 8-K dated February 20, 2002).
10.30	--	Compliance Sideletter dated February 20, 2002 between the Company and Mellon Ventures, L.P. (incorporated by reference

		to Exhibit 99.6 to the Company's Current Report on Form 8-K dated February 20, 2002).
10.31	--	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 by reference to Exhibit 10.1 to the Company's Quarterly Report on Form 10-Q for the quarter ended June 30, 2003).
10.32	--	Transition Services Agreement dated June 23, 2003 by and between the Company and Pinnacle Gas Resources, Inc. (incorporated by reference to Exhibit 10.1 to the Company's Quarterly Report on Form 10-Q for the quarter ended June 30, 2003).
***23.1	--	Consent of Ernst & Young LLP.
*23.2	--	Consent of Ryder Scott Company Petroleum Engineers.
*23.3	--	Consent of Fairchild and Wells, Inc.
**23.4	--	Consent of Baker Botts L.L.P. (included in Exhibit 5.1).
*24.1	--	Power of Attorney.

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* Previously filed.

** To be filed by amendment.

*** Filed herewith.