CONTINENTAL RESOURCES INC
Form S-1/A
November 17, 2006

As filed with the Securities and Exchange Commission on November 17, 2006

Registration No. 333-132257

SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

Amendment No. 4

to

FORM S-1

REGISTRATION STATEMENT

UNDER

THE SECURITIES ACT OF 1933

Continental Resources, Inc.

(Exact name of registrant as specified in charter)

Oklahoma	1311	73-0767549
(State or other jurisdiction of incorporation or organization)	(Primary Standard Industrial Classification Code Number)	(I.R.S. Employer Identification Number)

302 N. Independence

Enid, Oklahoma 73701

(580) 233-8955

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

Mark E. Monroe

President and Chief Operating Officer

302 N. Independence

Enid, Oklahoma 73701

(580) 233-8955

(Address, including zip code, and telephone number, including area code, of agent for service)

With a copy to:

David P. Oelman	**Joseph A. Hall**
Vinson & Elkins L.L.P.	**Davis Polk & Wardwell**
1001 Fannin, Suite 2300	**450 Lexington Avenue**
Houston, Texas 77002-6760	**New York, New York 10017**
(713) 758-2222	**(212) 450-4000**

Approximate date of commencement of proposed sale to the public: As soon as practicable on or after 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 this Form is filed to register additional securities for an offering pursuant to Rule 462(b) 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(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. ¨

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 the registration statement shall become effective on such date as the Securities and Exchange Commission, acting pursuant to said Section 8(a), may determine.

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The information 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 nor does it seek an offer to buy these securities in any state where the offer or sale is not permitted.

Subject to completion, dated November 17, 2006

PROSPECTUS

Shares

Continental Resources, Inc.

Common Stock

This is our initial public offering of common stock. The selling shareholder identified in this prospectus is offering shares of our common stock. We will not receive any proceeds from the sale of the shares by the selling shareholder. The estimated initial public offering price is between $ and $ per share.

Prior to this offering, there has been no public market for our common stock. Our common stock has been approved for listing on the New York Stock Exchange, subject to official notice of issuance, under the symbol CXP.

Investing in our common stock involves a high degree of risk. See Risk Factors beginning on page 13.

	Per share	Total

Initial public offering price	$	$
Underwriting discount	$	$
Proceeds to selling shareholder(1)	$	$

(1) Expenses, other than underwriting discounts, associated with the offering will be paid by us.

The selling shareholder has granted the underwriters an option for a period of 30 days to purchase up to additional shares of common stock to cover overallotments, if any. If such option is exercised in full, the total underwriting discount will be $ and the total proceeds to the selling shareholder will be $.

Neither the Securities and Exchange Commission nor any state securities commission has approved or disapproved of these securities or passed upon the adequacy or accuracy of this prospectus. Any representation to the contrary is a criminal offense.

The underwriters expect to deliver the shares of common stock to investors on , 2006.

JPMorgan **Merrill Lynch & Co.**

Citigroup

UBS Investment Bank

Petrie Parkman & Co.

Raymond James

, 2006

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Cautionary Statement Regarding Forward-Looking Statements

This prospectus contains forward-looking statements that are subject to a number of risks and uncertainties, many of which are beyond our control. All statements, other than statements of historical fact included in this prospectus, regarding our strategy, future operations, financial position, estimated revenues and losses, projected costs, prospects, plans and objectives of management are forward-looking statements. When used in this prospectus, the words could, believe, anticipate, intend, estimate, expect, project and similar expressions are intended to id forward-looking statements, although not all forward-looking statements contain such identifying words.

Forward-looking statements may include statements about our:

business strategy;

reserves;

technology;

financial strategy;

oil and natural gas realized prices;

timing and amount of future production of oil and natural gas;

the amount, nature and timing of capital expenditures;

drilling of wells;

competition and government regulations;

marketing of oil and natural gas;

exploitation or property acquisitions;

costs of exploiting and developing our properties and conducting other operations;

general economic conditions;

uncertainty regarding our future operating results; and

plans, objectives, expectations and intentions contained in this prospectus that are not historical.

All forward-looking statements speak only as of the date of this prospectus. You should not place undue reliance on these forward-looking statements. Although we believe that our plans, intentions and expectations reflected in or suggested by the forward-looking statements we make in this prospectus are reasonable, we can give no assurance that these plans, intentions or expectations will be achieved. We disclose important factors that could cause our actual results to differ materially from our expectations under Risk Factors and Management s Discussion and Analysis of Financial Condition and Results of Operations and elsewhere in this prospectus. These cautionary statements qualify all forward-looking statements attributable to us or persons acting on our behalf.

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Industry and Market Data

The market data and certain other statistical information used throughout this prospectus are based on independent industry publications, government publications or other published independent sources. Some data are also based on our good faith estimates. Although we believe these third-party sources are reliable, we have not independently verified the information and cannot guarantee its accuracy and completeness.

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Prospectus Summary

This summary highlights information contained elsewhere in this prospectus. You should read this entire prospectus carefully, including Risk Factors and our historical consolidated financial statements and the notes to those historical consolidated financial statements included elsewhere in this prospectus. Unless the context otherwise requires, references in this prospectus to Continental Resources, we, us, our, ours or company refer to Continental Resources, Inc. and its subsidiaries.

We have provided definitions for the oil and natural gas terms used in this prospectus in the Glossary of Oil and Natural Gas Terms beginning on page A-1 of this prospectus. Unless otherwise indicated, the information contained in this prospectus assumes that the underwriters do not exercise their overallotment option to purchase additional shares.

Our Business

We are an independent oil and natural gas exploration and production company with operations in the Rocky Mountain, Mid-Continent and Gulf Coast regions of the United States. We focus our exploration activities in large new or developing plays that provide us the opportunity to acquire undeveloped acreage positions for future drilling operations. We have been successful in targeting large repeatable resource plays where horizontal drilling, advanced fracture stimulation and enhanced recovery technologies provide the means to economically develop and produce oil and natural gas reserves from unconventional formations. As a result of these efforts, we have grown substantially through the drillbit, adding 86.2 MMBoe of proved oil and natural gas reserves through extensions and discoveries from January 1, 2001 through December 31, 2005 compared to 4.7 MMBoe added through proved reserve purchases during that same period.

As of December 31, 2005, our estimated proved reserves were 116.7 MMBoe, with estimated proved developed reserves of 80.3 MMBoe, or 69% of our total estimated proved reserves. Crude oil comprised 85% of our total estimated proved reserves. At December 31, 2005, we had 1,233 scheduled drilling locations on the 1,523,000 gross (961,000 net) acres that we held. For the year ended December 31, 2005 and the nine months ended September 30, 2006, we generated revenues of $375.8 million and $369.7 million, respectively, and operating cash flows of $265.3 million and $289.0 million, respectively.

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The following table summarizes our total estimated proved reserves, PV-10 and net producing wells as of December 31, 2005, average daily production for the three months ended September 30, 2006 and the reserve-to-production ratio in our principal regions. Our reserve estimates as of December 31, 2005 are based primarily on a reserve report prepared by Ryder Scott Company, L.P., our independent reserve engineers. In preparing its report, Ryder Scott Company, L.P. evaluated properties representing approximately 83% of our PV-10. Our technical staff evaluated properties representing the remaining 17% of our PV-10.

	At December 31, 2005				Average daily production		
	Proved reserves (MBoe)	Percent of total	PV-10(1) (in millions)	Net producing wells	Third quarter 2006 (Boe per day)	Percent of total	Annualized reserve/ production index(2)
Rocky Mountain:							
Red River units	67,711	58%	$ 1,215	187	11,162	44%	16.6
Bakken field	24,041	21%	505	34	7,800	30%	8.4
Other	9,065	8%	137	230	1,620	6%	15.3
Mid-Continent	15,472	13%	328	630	4,236	17%	10.0
Gulf Coast	376		19	23	812	3%	1.3
Total	116,665	100%	$ 2,204	1,104	25,630	100%	12.5

(1) PV-10 is a non GAAP financial measure and generally differs from Standardized Measure, the most directly comparable GAAP financial measure, because it does not include the effects of income taxes on future net revenues. However, our PV-10 and our Standardized Measure are equivalent because we are a subchapter S-corporation. In connection with the closing of this offering, we will convert to a subchapter C-corporation. Our pro-forma Standardized Measure, assuming our conversion to a subchapter C-corporation, was $1.4 billion at December 31, 2005. Neither PV-10 nor Standardized Measure represents an estimate of the fair market value of our oil and gas properties. We and others in the industry use PV-10 as a measure to compare the relative size and value of proved reserves held by companies without regard to the specific tax characteristics of such entities.

(2) The Annualized Reserve/Production Index is the number of years proved reserves would last assuming current production continued at the same rate. This index is calculated by dividing annualized third quarter 2006 production into the proved reserve quantity at December 31, 2005.

The following table provides additional information regarding our key development areas:

	At December 31, 2005					2006 Budget	
	Developed acres		Undeveloped acres		Scheduled drilling locations(1)	Wells planned for drilling	Capital expenditures (in millions)
	Gross	Net	Gross	Net			
Rocky Mountain:							
Red River units	144,176	128,047			135	23	$ 84
Bakken field	52,421	38,971	588,081	356,426	918	51	107
Other	45,720	36,153	358,649	208,612	71	11	39
Mid-Continent	152,734	99,279	115,746	73,582	96	83	62

Gulf Coast	41,842	11,890	23,598	7,873	13	9	9
Total	436,893	314,340	1,086,074	646,493	1,233	177	$ 301

(1) Scheduled drilling locations represent total gross locations specifically identified and scheduled by management as an estimate of our future multi-year drilling activities on existing acreage. Of the total locations shown in the table, 265 are classified as PUDs. As of September 30, 2006, we have commenced drilling 146 locations shown in the table, including 54 PUD locations. Scheduled drilling locations include 37 potential drilling sites in our New Albany Shale, Lewis Shale, Floyd Shale and Woodford Shale projects. While we owned 168,000 gross (72,000 net) undeveloped acres in these projects as of December 31, 2005, we have not sufficiently evaluated the opportunities on our acreage at this date to schedule further locations. Our actual drilling activities may change depending on oil and natural gas prices, the availability of capital, costs, drilling results, regulatory approvals and other factors. See Risk Factors Risks Relating to the Oil and Natural Gas Industry and Our Business.

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Our Business Strategy

Our goal is to increase shareholder value by finding and developing crude oil and natural gas reserves at costs that provide an attractive rate of return on our investment. The principal elements of our business strategy are:

Growth Through Drilling. Substantially all of our annual capital expenditures are invested in drilling projects and acreage and seismic acquisitions.

Internally Generate Prospects. Our technical staff has internally generated substantially all of the opportunities for the investment of our capital. Because we have been an early entrant in new or emerging plays, our costs to acquire undeveloped acreage have generally been less than those of later entrants into a developing play.

Focus on Unconventional Oil and Natural Gas Resource Plays. Our experience with horizontal drilling, advanced fracture stimulation and enhanced recovery technologies allows us to commercially develop unconventional oil and natural gas resource plays, such as the Red River B dolomite, Bakken Shale and Woodford Shale formations.

Acquire Significant Acreage Positions in New or Developing Plays. Our technical staff is focused on identifying and testing new unconventional oil and natural gas resource plays where significant reserves could be developed if commercial production rates can be achieved through advanced drilling, fracture stimulation and enhanced recovery techniques.

Our Business Strengths

We have a number of strengths that we believe will help us successfully execute our strategies:

Large Drilling and Acreage Inventory. Our large number of identified drilling locations in all of our areas of operations provide for a multi-year drilling inventory.

Horizontal Drilling and Enhanced Recovery Experience. In 1992, we drilled our initial horizontal well, and we have drilled over 300 horizontal wells since that time. We also have substantial experience with enhanced recovery methods and currently serve as the operator of 48 waterflood units and eight high-pressure air injection units.

Control Operations Over a Substantial Portion of our Assets and Investments. As of December 31, 2005, we operated properties comprising 97% of our PV-10. By controlling operations, we are able to more effectively manage the cost and timing of exploration and development of our properties.

Experienced Management Team. Our senior management team has extensive expertise in the oil and gas industry. Our seven senior officers have an average of 25 years of oil and gas industry experience.

Strong Financial Position. As of November 14, 2006, we had outstanding borrowings under our credit facility of approximately $174.0 million. We believe that our planned exploration and development activities will be funded substantially from our operating cash flows.

Recent Events

Payment of Cash Dividends. On April 13 and August 15, 2006, we paid cash dividends of approximately $60.0 million and $27.6 million, respectively, to our shareholders for tax purposes and, subject to forfeiture, to holders of unvested restricted stock. In connection with the completion of this offering, we will convert from a subchapter S-corporation to a subchapter C-corporation, and we do not anticipate paying any additional cash dividends on our common stock in the foreseeable future.

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NYMEX and Related Oil Price Differential. The difference between the calendar month average of the NYMEX crude oil prices and our realized crude oil prices increased in the Rocky Mountain region during the nine months ended September 30, 2006 compared to the year ended December 31, 2005. For the year ended December 31, 2005, the average company-wide difference was $5.24 per Bbl. The company-wide difference for the nine months ended September 30, 2006 was $10.55 per Bbl. Factors affecting the difference include higher oil imports and production in the region, lower demand by local refineries due to downtime for maintenance and reduced seasonal demand for gasoline and downstream transportation capacity constraints. We are unable to predict when, or if, the difference will revert back to 2005 levels.

Acreage Acquisition. In April 2006, we purchased a 50% interest in 135,000 acres in the Marfa Basin in Presidio and Brewster Counties, Texas as well as overriding royalty interests covering a portion of the acreage for approximately $7 million. We plan to re-enter a well on the acreage to test the Woodford and Barnett equivalent shales during the second half of 2006.

North Dakota Bakken Joint Venture. In June 2006, we entered into an agreement with ConocoPhillips Company to form an area of mutual interest (AMI) within Dunn, McKenzie, Mountrail and Williams Counties, North Dakota and jointly drill wells to test the Bakken formation. Within the AMI, we own approximately 97,000 net acres. Initial wells proposed under the agreement establish exploration blocks covering the 1,280-acre spacing unit for the initial well and two adjacent 1,280-acre spacing units. Each party has the right to acquire from the other party an undivided 50% interest in the exploration block acreage owned by the other party at $500 per net acre. ConocoPhillips Company has proposed and we have agreed to participate in the initial three wells to be drilled under the agreement. As of November 14, 2006, one well was producing, one well was drilled and awaiting completion and one well was being drilled.

2007 Capital Expenditure Budget. On November 7, 2006, our Board of Directors approved a capital expenditure budget of $400 million for calendar year 2007 allocated as follows:

	Wells planned for drilling	Capital expenditures (in millions)
Rocky Mountain:		
Red River units	41	$ 123
Bakken field	65	113
Other	24	31
Mid-Continent	54	62
Gulf Coast	3	4
Total exploration and development drilling	187	$ 333
Capital facilities		28
Workover / recompletion		9
Land costs		19
Seismic		7
Vehicles, computers & other equipment		4
Total		$ 400

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Risk Factors

Investing in our common stock involves risks that include the speculative nature of oil and natural gas exploration, competition, volatile oil and natural gas prices and other material factors. You should read carefully the section entitled Risk Factors beginning on page 12 for an explanation of these risks before investing in our common stock. In particular, the following considerations may offset our business strengths or have a negative effect on our business strategy as well as on activities on our properties, which could cause a decrease in the price of our common stock and result in a loss of all or a portion of your investment:

- A substantial or extended decline in oil and natural gas prices may adversely affect our business, financial condition or results of operations and our ability to meet our capital expenditure obligations and financial commitments.
- Drilling for and producing oil and natural gas are high risk activities with many uncertainties that could adversely affect our business, financial condition or results of operations.
- Reserve estimates depend on many assumptions that may turn out to be inaccurate. Any material inaccuracies in these reserve estimates or underlying assumptions will materially affect the quantities and present value of our reserves.
- The results of enhanced recovery methods are uncertain.
- Our development and exploitation projects require substantial capital expenditures. We may be unable to obtain needed capital or financing on satisfactory terms, which could lead to a decline in our oil and natural gas reserves.
- If oil and natural gas prices decrease, we may be required to take write-downs of the carrying values of our oil and natural gas properties.
- A substantial portion of our producing properties are located in the Rocky Mountains, making us vulnerable to risks associated with operating in one major geographic area.
- Unless we replace our oil and natural gas reserves, our reserves and production will decline, which would adversely affect our cash flows and results of operations.
- The unavailability or high cost of additional drilling rigs, equipment, supplies, personnel and oilfield services could adversely affect our ability to execute our exploration and development plans within our budget and on a timely basis.
- We may incur substantial losses and be subject to substantial liability claims as a result of our oil and natural gas operations; we may not be insured for, or our insurance may be inadequate to protect us against, these risks.
- The inability of our significant customers to meet their obligations to us may adversely affect our financial results.

Following this offering, our Chairman and Chief Executive Officer will own approximately % of our outstanding common stock, giving him influence and control in corporate transactions and other matters.

For a discussion of other considerations that could negatively affect us, including risks related to this offering and our common stock, see Risk Factors and Cautionary Statement Regarding Forward-Looking Statements.

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Corporate History and Information

Continental Resources, Inc. is incorporated under the laws of the State of Oklahoma. We were originally formed in 1967 to explore, develop and produce oil and natural gas properties in Oklahoma. Through 1993, our activities and growth remained focused primarily in Oklahoma. In 1993, we expanded our activity into the Rocky Mountain and Gulf Coast regions. Through drilling success and strategic acquisitions, approximately 87% of our estimated proved reserves as of December 31, 2005 are located in the Rocky Mountain region.

We are currently a subchapter S-corporation under the rules and regulations of the Internal Revenue Service. However, upon the consummation of this offering, we will have more shareholders than the IRS rules and regulations governing S-corporations allow, and, therefore, we will convert automatically from a subchapter S-corporation to a subchapter C-corporation. In connection with this conversion, we will record a charge to earnings estimated to be approximately $152.9 million as of September 30, 2006 to recognize deferred taxes.

In addition, concurrent with the closing of this offering, we will effect an 11 for 1 stock split of our shares in the form of a stock dividend.

Our principal executive offices are located at 302 N. Independence, Enid, Oklahoma 73701, and our telephone number at that address is (580) 233-8955.

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The Offering

Common Stock Offered:

By the selling shareholder: shares

Overallotment option granted by the selling shareholder: shares

Common stock to be owned by the selling shareholder after the offering: shares (or shares if the underwriters overallotment option is exercised in full)

Common stock to be outstanding after the offering: 159,088,380 shares

Use of Proceeds:

We will not receive any proceeds from the sale of the shares of common stock by the selling shareholder. See Use of Proceeds.

Dividend Policy:

We do not anticipate paying any cash dividends on our common stock. See Dividend Policy.

Proposed New York Stock Exchange Symbol:

CXP

Other Information About This Prospectus:

Unless specifically stated otherwise, the information in this prospectus:

- is adjusted to reflect an 11 for 1 stock split of our shares of common stock to be effected in the form of a stock dividend concurrent with the consummation of this offering;
- assumes no exercise of the underwriters overallotment option to purchase additional shares; and
- assumes an initial public offering price of $, which is the midpoint of the range set forth on the front cover of this prospectus.

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Summary Historical and Pro Forma Consolidated Financial Data

This section presents our summary historical and pro forma consolidated financial data. The summary historical consolidated financial data presented below is not intended to replace our historical consolidated financial statements.

The following historical consolidated financial data, as it relates to each of the fiscal years ended December 31, 2003 through 2005, has been derived from our audited historical consolidated financial statements for such periods. The following historical consolidated financial data, as it relates to each of the nine month periods ended September 30, 2005 and 2006, has been derived from our unaudited historical consolidated financial statements for such periods. You should read the following summary historical consolidated financial data in connection with Capitalization, Management s Discussion and Analysis of Financial Condition and Results of Operations and our historical consolidated financial statements and related notes included elsewhere in this prospectus. The summary historical consolidated results are not necessarily indicative of results to be expected in future periods.

The summary pro forma financial data reflect the tax effects of our conversion, concurrent with the closing of this offering, from a subchapter S-corporation to a subchapter C-corporation and the earnings per share impact of our 11 for 1 stock split to be effected in the form of a stock dividend concurrent with the closing of this offering.

	Year ended December 31,			Nine months ended September 30,	
	2003	2004	2005	2005	2006
	(in thousands, except per share amounts)				
Statement of operations data:					
Revenues:					
Oil and natural gas sales	$ 138,948	$ 181,435	$ 361,833	$ 251,603	$ 358,004
Crude oil marketing and trading(1)	169,547	226,664			
Oil and natural gas service operations	9,114	10,811	13,931	10,447	11,735
Total revenues	317,609	418,910	375,764	262,050	369,739
Operating costs and expenses:					
Production expense	40,821	43,754	52,754	38,256	46,160
Production tax	10,251	12,297	16,031	10,930	16,610
Exploration expense	17,221	12,633	5,231	2,493	9,085
Crude oil marketing and trading(1)	166,731	227,210			
Oil and gas service operations	5,641	6,466	7,977	5,663	6,644
Depreciation, depletion, amortization and accretion	40,256	38,627	49,802	34,584	46,376
Property impairments	8,975	11,747	6,930	5,760	9,080
General and administrative(2)	9,604	12,400	31,266	24,847	19,814
(Gain) loss on sale of assets	(589)	150	(3,026)	(2,906)	(292)
Total operating costs and expenses	$ 298,911	$ 365,284	$ 166,965	$ 119,627	$ 153,477

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	Year ended December 31,			Nine months ended September 30,	
	2003	**2004**	**2005**	**2005**	**2006**
	(in thousands, except per share amounts)				
Income from operations	$ 18,698	$ 53,626	$ 208,799	$ 142,423	$ 216,262
Other income (expense)					
Interest expense	(19,761)	(23,617)	(14,220)	(11,109)	(8,522)
Loss on redemption on bonds		(4,083)			
Other	295	890	867	498	1,230
Total other income (expense)	(19,466)	(26,810)	(13,353)	(10,611)	(7,292)
Income (loss) from continuing operations before income taxes	(768)	26,816	195,446	131,812	208,970
Provision (benefit) for income taxes(3)			1,139	1,139	(132)
Income (loss) from continuing operations	(768)	26,816	194,307	130,673	209,102
Discontinued operations(4)	946	1,680			
Loss on sale of discontinued operations(4)		(632)			
Income before cumulative effect of change in accounting principle	178	27,864	194,307	130,673	209,102
Cumulative effect of change in accounting principle(5)	2,162				
Net income	$ 2,340	$ 27,864	$ 194,307	$ 130,673	$ 209,102
Basic earnings (loss) per share:					
From continuing operations	$ (0.05)	$ 1.87	$ 13.52	$ 9.09	$ 14.55
From discontinued operations(4)	0.06	0.11			
Loss on sale of discontinued operations(4)		(0.04)			
Before cumulative effect of change in accounting principle	0.01	1.94	13.52	9.09	14.55
Cumulative effect of change in accounting principle	0.15				
Net income per share	$ 0.16	$ 1.94	$ 13.52	$ 9.09	$ 14.55
Shares used in basic earnings per share	14,369	14,369	14,369	14,369	14,369
Diluted earnings (loss) per share:					
From continuing operations	$ (0.05)	$ 1.85	$ 13.42	$ 9.00	$ 14.40
From discontinued operations(4)	0.06	0.12			
Loss on sale of discontinued operations(4)		(0.04)			
Before cumulative effect of change in accounting principle	0.01	1.93	13.42	9.00	14.40
Cumulative effect of change in accounting principle	0.15				
Net income per share	$ 0.16	$ 1.93	$ 13.42	$ 9.00	$ 14.40
Shares used in diluted earnings per share	14,369	14,476	14,482	14,522	14,516

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	Year ended December 31,			Nine months ended September 30,	
	2003	2004	2005	2005	2006
	(in thousands, except per share amounts)				
Pro forma C-corporation and stock split data:					
Income (loss) from continuing operations before income taxes	$ (768)	$ 26,816	$ 195,446	$ 131,812	$ 208,970
Pro forma provision (benefit) for income taxes attributable to operations	(292)	10,190	74,269	50,089	79,409
Pro forma income (loss) from operations after tax	(476)	16,626	121,177	81,723	129,561
Discontinued operations net of tax(4)	587	1,042			
Loss on sale of discontinued operations(4)		(392)			
Cumulative effect of change in accounting principle net of tax	1,340				
Pro forma net income	$ 1,451	$ 17,276	$ 121,177	$ 81,723	$ 129,561
Pro forma basic earnings per share	$ 0.01	$ 0.11	$ 0.77	$ 0.52	$ 0.82
Pro forma diluted earnings per share	0.01	0.11	0.76	0.51	0.81
Other financial data:					
Cash dividends per share	$	$ 1.04	$ 0.14	$ 0.14	$ 6.06
EBITDAX (6)	88,750	116,498	285,344	198,089	287,009
Net cash provided by operations	65,246	93,854	265,265	161,974	288,999
Net cash used in investing	(108,791)	(72,992)	(133,716)	(83,295)	(219,436)
Net cash provided by (used in) financing	43,302	(7,245)	(141,467)	(85,686)	(71,162)
Capital expenditures	114,145	94,307	144,800	94,179	221,288
Balance sheet data (at period end):					
Cash and cash equivalents	$ 2,277	$ 15,894	$ 6,014	$ 8,927	$ 4,456
Property and equipment, net	439,432	434,339	509,393	476,019	672,415
Total assets	484,988	504,951	600,234	575,594	782,896
Long-term debt, including current maturities	290,920	290,522	143,000	196,000	160,000
Shareholders equity	116,932	130,385	324,730	261,098	446,282

(1) Crude oil marketing and trading captions consist of our marketing activities under which crude oil production was sold at the wellhead and transported to a local hub where we purchased the barrels back to exchange at Cushing, Oklahoma in order to minimize pricing differentials with the NYMEX oil futures contract. We adopted Emerging Issues Task Force (EITF) 04-13 on January 1, 2005, which allowed certain purchase and sales transactions with the same counterparty to be combined and accounted for as a single transaction under the guidance of Accounting Principles Board Opinion No. 29. In 2005, we netted $39.8 million of crude oil marketing and trading revenues and $39.7 million of crude oil marketing and trading expenses under oil and natural gas sales. Prior to the adoption of EITF 04-13, we presented crude oil marketing and trading revenues and expenses gross under the guidance provided by EITF 99-19, Reporting Revenues Gross as a Principal and/or Net as an Agent. Effective March 2005, we ceased marketing our crude oil production under these arrangements. Thereafter, we have sold our crude oil at the wellhead. Certain of these sales have been to our affiliates, as described under Certain Relationships and Related Party Transactions.

(2) We have included stock-based compensation of $0.2 million, $2.0 million, $13.7 million, $12.3 million and $5.0 million in general and administrative expenses for the years ended December 31, 2003, 2004 and 2005 and the nine months ended September 30, 2005 and 2006, respectively. Our stock based compensation plan requires us to purchase vested shares at the employee s request based on an internally calculated value of our stock. Amounts noted herein represent the increase in our liability associated with our purchase obligation. The valuation is based on the book value of our shareholders equity adjusted for our PV-10 as of each calendar quarter. Our requirement to purchase vested shares will be eliminated once we begin reporting under Section 12 of the Securities Exchange Act of 1934, as amended (the Exchange Act). As a result of this change, we will recognize a charge of approximately $ upon completion of this offering, assuming an offering price at the midpoint of the range set forth on the cover page of this prospectus. See Capitalization.

(3) Properties owned by us at May 31, 1997, the date we converted into a subchapter S-corporation from a subchapter C-corporation, may be subject to federal taxation if sold for an amount in excess of the then tax basis for the sold assets. During 2005, we incurred federal taxes due to the sale of assets acquired prior to May 31, 1997. The benefit recorded during 2006 reflects a change in estimate of the original provision recorded for federal taxes incurred.

(4) In July 2004, we sold all of the outstanding stock in Continental Gas, Inc., a wholly owned subsidiary, to our shareholders. The Continental Gas, Inc. assets included seven gas gathering systems and three gas-processing plants. These assets represented our entire gas gathering, marketing and processing segment. We have accounted for these operations as discontinued operations.

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(5) We adopted Statement of Financial Accounting Standards No. 143, Accounting for Asset Retirement Obligations and recorded the cumulative effect of the change in accounting principle on January 1, 2003.

(6) EBITDAX represents earnings before interest expense, income taxes (when applicable), depreciation, depletion, amortization and accretion, property impairments, exploration expense and non-cash compensation expense. EBITDAX is not a measure of net income or cash flow as determined by generally accepted accounting principles (GAAP). EBITDAX should not be considered as an alternative to, or more meaningful than, net income or cash flow as determined in accordance with GAAP or as an indicator of a company s operating performance or liquidity. Certain items excluded from EBITDAX are significant components in understanding and assessing a company s financial performance, such as a company s cost of capital and tax structure, as well as the historic costs of depreciable assets, none of which are components of EBITDAX. Our computations of EBITDAX may not be comparable to other similarly titled measures of other companies. We believe that EBITDAX is a widely followed measure of operating performance and may also be used by investors to measure our ability to meet future debt service requirements, if any. Our credit facility requires that we maintain a total debt to EBITDAX ratio of no greater than 3.75 to 1 on a rolling four-quarter basis. Our credit facility defines EBITDAX consistently with the definition of EBITDAX utilized and presented by us. At December 31, 2005 and September 30, 2006, this ratio was approximately 0.5 to 1 and 0.4 to 1, respectively. The following table represents a reconciliation of our net income to EBITDAX:

	Year ended December 31,			Nine months ended September 30,	
	2003	2004	2005	2005	2006
	(in thousands)				
Net income	$ 2,340	$ 27,864	$ 194,307	$ 130,673	$ 209,102
Interest expense	19,761	23,617	14,220	11,109	8,522
Provision (benefit) for income taxes			1,139	1,139	(132)
Depreciation, depletion, amortization and accretion	40,256	38,627	49,802	34,584	46,376
Property impairments	8,975	11,747	6,930	5,760	9,080
Exploration expense	17,221	12,633	5,231	2,493	9,085
Equity compensation	197	2,010	13,715	12,331	4,976
EBITDAX	$ 88,750	$ 116,498	$ 285,344	$ 198,089	$ 287,009

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Summary Reserve, Production and Operating Data

The following table presents summary data with respect to our estimated net proved oil and natural gas reserves as of the dates indicated. Our reserve estimates as of December 31, 2003, 2004 and 2005 are based primarily on reserve reports prepared by Ryder Scott Company, L.P., our independent reserve engineers. In preparing its reports, Ryder Scott Company, L.P. evaluated properties representing approximately 83% of our PV-10 as of the end of each period. Our technical staff evaluated our remaining properties. A copy of Ryder Scott Company, L.P. s summary report as of December 31, 2005 is included in this prospectus beginning on page B-1. All calculations of estimated net proved reserves have been made in accordance with the rules and regulations of the Securities and Exchange Commission, or the SEC. For additional information regarding our reserves, see Business and Properties Proved Reserves.

	As of December 31,		
	2003	2004	2005
Proved reserves:			
Oil (MBbls)	73,000	80,602	98,645
Natural gas (MMcf)	67,096	60,620	108,118
Oil equivalent (MBoe)	84,183	90,705	116,665
Proved developed reserves percentage	55%	83%	69%
PV-10 (in millions)(1)	$ 815	$ 1,114	$ 2,204
Estimated reserve life (in years)	16.0	17.6	16.2
Costs incurred (in thousands):			
Property acquisition costs	$ 8,683	$ 12,456	$ 16,763
Exploration costs	11,981	30,867	9,289
Development costs	75,396	53,036	117,837
Total	$ 96,060	$ 96,359	$ 143,889

(1) PV-10 is a non GAAP financial measure and generally differs from Standardized Measure, the most directly comparable GAAP financial measure, because it does not include the effects of income taxes on future net revenues. However, our PV-10 and our Standardized Measure are equivalent because we are a subchapter S-corporation. In connection with the closing of this offering, we will convert to a subchapter C-corporation. Our pro-forma Standardized Measure, assuming our conversion to a subchapter C-corporation, was $1.4 billion at December 31, 2005. Neither PV-10 nor Standardized Measure represents an estimate of the fair market value of our oil and gas properties. We and others in the industry use PV-10 as a measure to compare the relative size and value of proved reserves held by companies without regard to the specific tax characteristics of such entities.

The following table sets forth summary data with respect to our production results, average sales prices and production costs on a historical basis for the periods presented:

	Year ended December 31,			Nine months ended September 30,	
	2003	2004	2005	2005	2006
Net production volumes:					

Oil (MBbls)(1)	3,463	3,688	5,708	4,045	5,454
Natural gas (MMcf)	10,751	8,794	9,006	6,748	6,755
Oil equivalents (MBoe)	5,255	5,154	7,209	5,170	6,580
Average prices(1):					
Oil, without hedges ($/Bbl)	$ 28.88	$ 38.85	$ 52.45	$ 51.90	$ 58.05
Oil, with hedges ($/Bbl)	25.98	37.12	52.45	51.90	58.05
Natural gas ($/Mcf)	4.55	5.06	6.93	6.17	6.22
Oil equivalents, without hedges ($/Boe)	28.35	36.45	50.19	48.67	54.50
Oil equivalents, with hedges ($/Boe)	26.44	35.20	50.19	48.67	54.50
Costs and expenses(1):					
Production expense ($/Boe)	$ 7.77	$ 8.49	$ 7.32	$ 7.40	$ 7.03
Production tax ($/Boe)	1.95	2.39	2.22	2.11	2.53
General and administrative ($/Boe)	1.83	2.41	4.34	4.81	3.02
DD&A expense ($/Boe)(2)	7.10	7.02	6.50	6.26	6.69

(1) Oil sales volumes are 10 MBbls less than oil production volumes for the nine months ended September 30, 2006. Average prices and per unit costs have been calculated using sales volumes.

(2) Rate is determined based on DD&A expense derived from oil and natural gas assets.

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Risk Factors

You should carefully consider each of the risks described below, together with all of the other information contained in this prospectus, before deciding to invest in shares of our common stock. If any of the following risks develop into actual events, our business, financial condition or results of operations could be materially adversely affected, the trading price of your shares could decline and you may lose all or part of your investment.

Risks Relating to the Oil and Natural Gas Industry and Our Business

A substantial or extended decline in oil and natural gas prices may adversely affect our business, financial condition or results of operations and our ability to meet our capital expenditure obligations and financial commitments.

The price we receive for our oil and natural gas production heavily influences our revenue, profitability, access to capital and future rate of growth. Oil and natural gas are commodities and, therefore, their prices are subject to wide fluctuations in response to relatively minor changes in supply and demand. Historically, the markets for oil and natural gas have been volatile. These markets will likely continue to be volatile in the future. The prices we receive for our production, and the levels of our production, depend on numerous factors beyond our control. These factors include the following:

- changes in global supply and demand for oil and natural gas;
- the actions of the Organization of Petroleum Exporting Countries, or OPEC;
- the price and quantity of imports of foreign oil and natural gas;
- political conditions in or affecting other oil-producing and natural gas-producing countries, including the current conflicts in the Middle East and conditions in South America and Russia;
- the level of global oil and natural gas exploration and production;
- the level of global oil and natural gas inventories;
- localized supply and demand fundamentals and transportation availability;

weather conditions;

technological advances affecting energy consumption; and

the price and availability of alternative fuels.

Lower oil and natural gas prices may also reduce the amount of oil and natural gas that we can produce economically. Substantial decreases in oil and natural gas prices would render uneconomic a significant portion of our exploitation projects. This may result in our having to make significant downward adjustments to our estimated proved reserves. As a result, a substantial or extended decline in oil or natural gas prices may materially and adversely affect our future business, financial condition, results of operations, liquidity or ability to finance planned capital expenditures.

In addition, because our producing properties are geographically concentrated in the Rocky Mountain region, we are vulnerable to fluctuations in pricing in that area. In particular, 80% of our production during the third quarter of 2006 was from the Rocky Mountain region. As a result of this concentration, we may be disproportionately exposed to the impact of regional supply and demand factors, transportation capacity

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constraints, curtailment of production or interruption of transportation of oil produced from the wells in these areas. Such factors can cause significant fluctuation in our realized oil and natural gas prices. For example, the company-wide difference between the average NYMEX oil price and our average realized oil price for the year ended December 31, 2005 was $5.24 per Bbl, whereas the company-wide difference between the NYMEX oil price and our realized oil price for the nine months ended September 30, 2006 was $10.55 per Bbl. The increase in the difference was caused by higher oil imports and production in the Rocky Mountain region, lower demand by local Rocky Mountain refineries due to downtime for maintenance and reduced seasonal demand for gasoline and downstream transportation capacity constraints. We are unable to predict when, or if, the difference will revert back to 2005 levels. If such significant price differentials continue, our future business, financial condition and results of operations may be materially adversely affected.

Drilling for and producing oil and natural gas are high risk activities with many uncertainties that could adversely affect our business, financial condition or results of operations.

Our future financial condition and results of operations will depend on the success of our exploitation, exploration, development and production activities. Our oil and natural gas exploration and production activities are subject to numerous risks beyond our control, including the risk that drilling will not result in commercially viable oil or natural gas production. Our decisions to purchase, explore, develop or otherwise exploit prospects or properties will depend in part on the evaluation of data obtained through geophysical and geological analyses, production data and engineering studies, the results of which are often inconclusive or subject to varying interpretations. For a discussion of the uncertainty involved in these processes, see Reserve estimates depend on many assumptions that may turn out to be inaccurate. Any material inaccuracies in these reserve estimates or underlying assumptions will materially affect the quantities and present value of our reserves. Our cost of drilling, completing and operating wells is often uncertain before drilling commences. Overruns in budgeted expenditures are common risks that can make a particular project uneconomical. Further, many factors may curtail, delay or cancel drilling, including the following:

- delays imposed by or resulting from compliance with regulatory requirements;
- pressure or irregularities in geological formations;
- shortages of or delays in obtaining equipment and qualified personnel;
- equipment failures or accidents;
- adverse weather conditions, such as hurricanes and tropical storms;
- reductions in oil and natural gas prices;
- title problems; and
- limitations in the market for oil and natural gas.

Reserve estimates depend on many assumptions that may turn out to be inaccurate. Any material inaccuracies in these reserve estimates or underlying assumptions will materially affect the quantities and present value of our reserves.

The process of estimating oil and natural gas reserves is complex. It requires interpretations of available technical data and many assumptions, including assumptions relating to economic factors. Any significant inaccuracies in these interpretations or assumptions could materially affect the estimated quantities and present value of reserves shown in this prospectus. See Business and Properties Proved Reserves for information about our oil and natural gas reserves.

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In order to prepare our estimates, we must project production rates and timing of development expenditures. We must also analyze available geological, geophysical, production and engineering data. The extent, quality and reliability of this data can vary. The process also requires economic assumptions about matters such as oil and natural gas prices, drilling and operating expenses, capital expenditures, taxes and availability of funds.

Actual future production, oil and natural gas prices, revenues, taxes, development expenditures, operating expenses and quantities of recoverable oil and natural gas reserves most likely will vary from our estimates. Any significant variance could materially affect the estimated quantities and present value of reserves shown in this prospectus. In addition, we may adjust estimates of proved reserves to reflect production history, results of exploration and development, prevailing oil and natural gas prices and other factors, many of which are beyond our control.

For example, our initial well in the Bakken Field was completed in August 2003. As of December 31, 2005, we had 10.8 MMBoe of proved producing reserves assigned to 62 producing wells and 13.2 MMBoe of proved undeveloped reserves assigned to 60 undrilled locations. The Bakken Field contained 21% of our total proved reserves and 36% of our total proved undeveloped reserves as of December 31, 2005. Due to the limited production history of our wells in the Bakken Field, the estimates of future production associated with such properties may be subject to greater variance to actual production than would be the case with properties having a longer production history.

You should not assume that the present value of future net revenues from our proved reserves referred to in this prospectus is the current market value of our estimated oil and natural gas reserves. In accordance with SEC requirements, we generally base the estimated discounted future net cash flows from our proved reserves on prices and costs on the date of the estimate. Actual future prices and costs may differ materially from those used in the present value estimate. If oil prices decline by $1.00 per Bbl, then our PV-10 as of December 31, 2005 would decrease from $2,204 million to $2,156 million. If natural gas prices decline by $0.10 per Mcf, then our PV-10 as of December 31, 2005 would decrease from $2,204 million to $2,199 million.

Our use of enhanced recovery methods creates uncertainties that could adversely affect our results of operations and financial condition.

We inject water and high-pressure air into formations on some of our properties to increase the production of oil and natural gas. The additional production and reserves attributable to the use of these enhanced recovery methods are inherently difficult to predict. If our enhanced recovery programs do not allow for the extraction of oil and natural gas in the manner or to the extent that we anticipate, our future results of operations and financial condition could be materially adversely affected.

Our development and exploitation projects require substantial capital expenditures. We may be unable to obtain needed capital or financing on satisfactory terms, which could lead to a decline in our oil and natural gas reserves.

The oil and natural gas industry is capital intensive. We make and expect to continue to make substantial capital expenditures in our business for the development, exploitation, production and acquisition of oil and natural gas reserves. To date, these capital expenditures have been financed with cash generated by operations and through borrowings from banks and from our principal shareholder. We intend to finance our future capital expenditures primarily through cash flow from operations and through borrowings under our revolving credit facility; however, our financing needs may require us to alter or increase our capitalization substantially through the issuance of debt or equity securities. The issuance of additional debt will require that a portion of our cash flow from operations be used for the payment of interest and principal on our debt, thereby reducing our ability to use cash flow to fund working capital, capital expenditures and acquisitions. The issuance of additional equity securities could have a dilutive effect on the value of your common stock.

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Our cash flow from operations and access to capital are subject to a number of variables, including:

- our proved reserves;
- the level of oil and natural gas we are able to produce from existing wells;
- the prices at which our oil and natural gas are sold; and
- our ability to acquire, locate and produce new reserves.

If our revenues or the borrowing base under our credit facility decrease as a result of lower oil or natural gas prices, operating difficulties, declines in reserves or for any other reason, we may have limited ability to obtain the capital necessary to sustain our operations at current levels. If additional capital is needed, we may not be able to obtain debt or equity financing. If cash generated by operations or cash available under our revolving credit facility is not sufficient to meet our capital requirements, the failure to obtain additional financing could result in a curtailment of our operations relating to development of our prospects, which in turn could lead to a decline in our oil and natural gas reserves, and could adversely affect our business, financial condition and results of operations.

If oil and natural gas prices decrease, we may be required to take write-downs of the carrying values of our oil and natural gas properties.

Accounting rules require that we review periodically the carrying value of our oil and natural gas properties for possible impairment. Based on specific market factors and circumstances at the time of prospective impairment reviews, and the continuing evaluation of development plans, production data, economics and other factors, we may be required to write down the carrying value of our oil and natural gas properties. A write-down constitutes a non-cash charge to earnings. We may incur impairment charges in the future, which could have a material adverse effect on our results of operations for the periods in which such charges are taken.

Unless we replace our oil and natural gas reserves, our reserves and production will decline, which would adversely affect our cash flows and results of operations.

Unless we conduct successful development, exploitation and exploration activities or acquire properties containing proved reserves, our proved reserves will decline as those reserves are produced. Producing oil and natural gas reservoirs generally are characterized by declining production rates that vary depending upon reservoir characteristics and other factors. Our future oil and natural gas reserves and production, and therefore our cash flow and results of operations, are highly dependent on our success in efficiently developing and exploiting our current reserves and economically finding or acquiring additional recoverable reserves. We may not be able to develop, exploit, find or acquire sufficient additional reserves to replace our current and future production.

The unavailability or high cost of additional drilling rigs, equipment, supplies, personnel and oilfield services could adversely affect our ability to execute our exploration and development plans within our budget and on a timely basis.

Shortages or the high cost of drilling rigs, equipment, supplies, personnel or oilfield services could delay or adversely affect our development and exploration operations, which could have a material adverse effect on our business, financial condition or results of operations.

We may incur substantial losses and be subject to substantial liability claims as a result of our oil and natural gas operations; we may not be insured for, or our insurance may be inadequate to protect us against, these risks.

We are not insured against all risks. Losses and liabilities arising from uninsured and underinsured events could materially and adversely affect our business, financial condition or results of operations. Our oil and

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natural gas exploration and production activities are subject to all of the operating risks associated with drilling for and producing oil and natural gas, including the possibility of:

- environmental hazards, such as uncontrollable flows of oil, natural gas, brine, well fluids, toxic gas or other pollution into the environment, including groundwater and shoreline contamination;
- abnormally pressured formations;
- mechanical difficulties, such as stuck oilfield drilling and service tools and casing collapse;
- fires, explosions and ruptures of pipelines in connection with our high-pressure air injection operations;
- personal injuries and death; and
- natural disasters.

Any of these risks could adversely affect our ability to conduct operations or result in substantial losses to our company as a result of:

- injury or loss of life;
- damage to and destruction of property, natural resources and equipment;
- pollution and other environmental damage;
- regulatory investigations and penalties;
- suspension of our operations; and
- repair and remediation costs.

We may elect not to obtain insurance 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 that is not fully covered by insurance could have a material adverse effect on our business, financial condition and results of operations.

Prospects that we decide to drill may not yield oil or natural gas in commercially viable quantities.

Prospects that we decide to drill that do not yield oil or natural gas in commercially viable quantities will adversely affect our result of operations and financial condition. In this prospectus, we describe some of our current prospects and our plans to explore those prospects. Our prospects are in various stages of evaluation, ranging from a prospect which is ready to drill to a prospect that will require substantial additional seismic data processing and interpretation. There is no way to predict in advance of drilling and testing whether any particular prospect will yield oil or natural gas in sufficient quantities to recover drilling or completion costs or to be economically viable. The use of seismic data and other technologies and the study of producing fields in the same area will not enable us to know conclusively prior to drilling whether oil or natural gas will be present or, if present, whether oil or natural gas will be present in commercial quantities. We cannot assure you that the analogies we draw from available data from other wells, more fully explored prospects or producing fields will be applicable to our drilling prospects.

Our identified drilling locations are scheduled out over several years, making them susceptible to uncertainties that could materially alter the occurrence or timing of their drilling.

Our management has specifically identified and scheduled drilling locations as an estimation of our future multi-year drilling activities on our existing acreage. As of December 31, 2005, we had identified and scheduled

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1,233 gross drilling locations. These scheduled drilling locations represent a significant part of our growth strategy. Our ability to drill and develop these locations depends on a number of uncertainties, including oil and natural gas prices, the availability of capital, costs, drilling results, regulatory approvals and other factors. Because of these uncertainties, we do not know if the numerous potential drilling locations we have identified will ever be drilled or if we will be able to produce oil or natural gas from these or any other potential drilling locations. In addition, unless production is established within the spacing units covering the undeveloped acres on which some of the locations are identified, the leases for such acreage will expire. As of December 31, 2005, we had 93,922, 123,214 and 160,891 net acres expiring in 2006, 2007 and 2008, respectively. As such, our actual drilling activities may materially differ from those presently identified, which could adversely affect our business.

Market conditions or operational impediments may hinder our access to oil and natural gas markets or delay our production.

Market conditions or the unavailability of satisfactory oil and natural gas transportation arrangements may hinder our access to oil and natural gas markets or delay our production. The availability of a ready market for our oil and natural gas production depends on a number of factors, including the demand for and supply of oil and natural gas and the proximity of reserves to pipelines and terminal facilities. Our ability to market our production depends in substantial part on the availability and capacity of gathering systems, pipelines and processing facilities owned and operated by third parties. Our failure to obtain such services on acceptable terms could materially harm our business. We may be required to shut in wells due to lack of a market or inadequacy or unavailability of crude oil or natural gas pipeline or gathering system capacity. If that were to occur, then we would be unable to realize revenue from those wells until production arrangements were made to deliver to market.

We have been an early entrant into new or emerging plays; as a result, our drilling results in these areas are uncertain, and the value of our undeveloped acreage will decline if drilling results are unsuccessful.

While our costs to acquire undeveloped acreage in new or emerging plays have generally been less than those of later entrants into a developing play, our drilling results in these areas are more uncertain than drilling results in areas that are developed and producing. Since new or emerging plays have limited or no production history, we are unable to use past drilling results in those areas to help predict our future drilling results. As a result, our cost of drilling, completing and operating wells in these areas may be higher than initially expected, and the value of our undeveloped acreage will decline if drilling results are unsuccessful.

We are subject to complex federal, state, local, provincial and other laws and regulations that could adversely affect the cost, manner or feasibility of conducting our operations.

Our oil and natural gas exploration, production and transportation operations are subject to complex and stringent laws and regulations. In order to conduct our operations in compliance with these laws and regulations, we must obtain and maintain numerous permits, approvals and certificates from various federal, state, local and provincial governmental authorities. We may incur substantial costs in order to maintain compliance with these existing laws and regulations. In addition, our costs of compliance may increase if existing laws and regulations are revised or reinterpreted, or if new laws and regulations become applicable to our operations. Such costs could have a material adverse effect on our business, financial condition and results of operations.

Our business is subject to federal, state, local and provincial laws and regulations as interpreted and enforced by governmental authorities possessing jurisdiction over various aspects of the exploration for, and the production and transportation of, oil and natural gas. Failure to comply with such laws and regulations, as interpreted and enforced, could have a material adverse effect on our business, financial condition and results of operations. See Business and Properties Environmental, Health and Safety Regulation and Business and

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Properties Regulation of the Oil and Natural Gas Industry for a description of the laws and regulations that affect us.

Our operations expose us to significant costs and liabilities with respect to environmental and operational safety matters.

We may incur significant costs and liabilities as a result of environmental, health and safety requirements applicable to our oil and natural gas exploration, production and transportation activities. These costs and liabilities could arise under a wide range of federal, state, local and provincial laws and regulations relating to protection of the environment, health and safety, including regulations and enforcement policies that have tended to become increasingly strict over time. Failure to comply with these laws and regulations may result in the assessment of administrative, civil and criminal penalties, imposition of cleanup and site restoration costs and liens, and, to a lesser extent, issuance of injunctions to limit or cease operations. In addition, claims for damages to persons or property, including natural resources, may result from the environmental, health and safety impacts of our operations.

Strict, joint and several liability may be imposed under certain environmental laws, which could cause us to become liable for the conduct of others or for consequences of our own actions that were in compliance with all applicable laws at the time those actions were taken. New laws, regulations or enforcement policies could be more stringent and impose unforeseen liabilities or significantly increase compliance costs. If we were not able to recover the resulting costs through insurance or increased revenues, our business, financial condition or results of operations could be adversely affected. See Business and Properties Environmental, Health and Safety Regulation for more information.

Competition in the oil and natural gas industry is intense, making it more difficult for us to acquire properties, market oil and natural gas and secure trained personnel.

We operate in a highly competitive environment for acquiring properties, marketing oil and natural gas and securing trained personnel. Many of our competitors possess and employ financial, technical and personnel resources substantially greater than ours, which can be particularly important in the areas in which we operate. Those companies may be able to pay more for productive oil and natural gas properties and exploratory prospects and to evaluate, bid for and purchase a greater number of properties and prospects than our financial or personnel resources permit. In addition, those companies may be able to offer better compensation packages to attract and retain qualified personnel than we are able to offer. The cost to attract and retain qualified personnel has increased over the past two years due to competition and may increase substantially in the future. Our ability to acquire additional prospects and to find and develop reserves in the future will depend on our ability to evaluate and select suitable properties and to consummate transactions in a highly competitive environment. Also, there is substantial competition for capital available for investment in the oil and natural gas industry. We may not be able to compete successfully in the future in acquiring prospective reserves, developing reserves, marketing hydrocarbons, attracting and retaining quality personnel and raising additional capital. Our failure to acquire properties, market oil and natural gas and secure trained personnel and increased compensation for trained personnel could have a material adverse effect on our business.

The loss of senior management or technical personnel could adversely affect operations.

To a large extent, we depend on the services of our senior management and technical personnel. The loss of the services of our senior management or technical personnel, including Harold G. Hamm, our Chairman and Chief Executive Officer, could have a material adverse effect on our operations. We do not maintain, nor do we plan to obtain, any insurance against the loss of any of these individuals.

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Terrorist attacks aimed at our energy operations could adversely affect our business.

The continued threat of terrorism and the impact of military and other government action has led and may lead to further increased volatility in prices for oil and natural gas and could affect these commodity markets or financial markets used by us. In addition, the U.S. government has issued warnings that energy assets may be a future target of terrorist organizations. These developments have subjected our oil and natural gas operations to increased risks. Any future terrorist attack on our facilities, those of our customers and, in some cases, those of other energy companies, could have a material adverse effect on our business.

Seasonal weather conditions and lease stipulations adversely affect our ability to conduct drilling activities in some of the areas where we operate.

Oil and natural gas operations in the Rocky Mountains are adversely affected by seasonal weather conditions and lease stipulations designed to protect various wildlife. In certain areas, including parts of Montana, North Dakota, South Dakota, Utah and Wyoming, drilling and other oil and natural gas activities can only be conducted during the spring and summer months. This limits our ability to operate in those areas and can intensify competition during those months for drilling rigs, oilfield equipment, services, supplies and qualified personnel, which may lead to periodic shortages. These constraints and the resulting shortages or high costs could delay our operations and materially increase our operating and capital costs.

Our credit facility contains certain covenants that may inhibit our ability to make certain investments, incur additional indebtedness and engage in certain other transactions, which could adversely affect our ability to meet our future goals.

Our credit facility includes certain covenants that, among other things, restrict:

- our investments, loans and advances and the paying of dividends and other restricted payments;
- our incurrence of additional indebtedness;
- the granting of liens, other than liens created pursuant to the credit facility and certain permitted liens;
- mergers, consolidations and sales of all or substantial part of our business or properties;
- the hedging, forward sale or swap of our production of crude oil or natural gas or other commodities;
- the sale of assets; and

our capital expenditures.

Our credit facility requires us to maintain certain financial ratios, such as leverage ratios. All of these restrictive covenants may restrict our ability to expand or pursue our business strategies. Our ability to comply with these and other provisions of our credit facility may be impacted by changes in economic or business conditions, results of operations or events beyond our control. The breach of any of these covenants could result in a default under our credit facility, in which case, depending on the actions taken by the lenders thereunder or their successors or assignees, such lenders could elect to declare all amounts borrowed under our credit facility, together with accrued interest, to be due and payable. If we were unable to repay such borrowings or interest, our lenders could proceed against their collateral. If the indebtedness under our credit facility were to be accelerated, our assets may not be sufficient to repay in full such indebtedness.

The inability of our significant customers to meet their obligations to us may adversely affect our financial results.

We are subject to credit risk due to concentration of our crude oil and natural gas receivables with several significant customers. The two largest purchasers of our oil and natural gas during the nine months ended

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September 30, 2006 accounted for 18% and 15% of our total oil and natural gas sales revenues. We do not require our customers to post collateral. The inability of our significant customers to meet their obligations to us may adversely affect our financial results.

Risks Relating to the Offering and Our Common Stock

The initial public offering price of our common stock may not be indicative of the market price of our common stock after this offering. In addition, our stock price may be volatile.

Prior to this offering, there has been no public market for our common stock. An active market for our common stock may not develop or may not be sustained after this offering. The initial public offering price of our common stock was determined by negotiations between us and representatives of the underwriters, based on numerous factors which we discuss in the Underwriting section of this prospectus. This price may not be indicative of the market price for our common stock after this initial public offering. The market price of our common stock could be subject to significant fluctuations after this offering, and may decline below the initial public offering price. You may not be able to resell your shares at or above the initial public offering price. The following factors could affect our stock price:

- our operating and financial performance and prospects;
- quarterly variations in the rate of growth of our financial indicators, such as net income per share, net income and revenues;
- changes in revenue or earnings estimates or publication of reports by equity research analysts;
- speculation in the press or investment community;
- sales of our common stock by us, Harold G. Hamm or other shareholders, or the perception that such sales may occur;
- general market conditions, including fluctuations in commodity prices; and
- domestic and international economic, legal and regulatory factors unrelated to our performance.

The stock markets in general have experienced extreme volatility that has often been unrelated to the operating performance of particular companies. These broad market fluctuations may adversely affect the trading price of our common stock.

Following this offering, our Chairman and Chief Executive Officer will own approximately % of our outstanding common stock, giving him influence and control in corporate transactions and other matters, including a sale of our company.

As of the closing of this offering, Harold G. Hamm, our Chairman and Chief Executive Officer, will beneficially own shares of our outstanding common stock (assuming no exercise of the underwriters overallotment option), representing approximately % of our outstanding common stock. As a result, Mr. Hamm will continue to be our controlling shareholder and will continue to be able to control the election of our directors, determine our corporate and management policies and determine, without the consent of our other shareholders, the outcome of certain corporate transactions or other matters submitted to our shareholders for approval, including potential mergers or acquisitions, asset sales and other significant corporate transactions. As controlling shareholder, Mr. Hamm could cause, delay or prevent a change of control of our company. The interests of Mr. Hamm may not coincide with the interests of other holders of our common stock.

Several affiliated companies controlled by Mr. Hamm provide oilfield, gathering and processing, marketing and other services to us. We expect these transactions will continue in the future and may result in conflicts of

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interest between Mr. Hamm s affiliated companies and us. We can provide no assurance that any such conflicts will be resolved in our favor.

Purchasers of common stock in this offering will experience immediate and substantial dilution of $ per share.

Based on an assumed initial public offering price of $ per share, purchasers of our common stock in this offering will experience an immediate and substantial dilution of $ per share in the net tangible book value per share of common stock from the initial public offering price, and our net tangible book value as of September 30, 2006 was $2.81 per share. See Dilution for a complete description of the calculation of net tangible book value.

The requirements of being a public company, including compliance with the reporting requirements of the Exchange Act and the requirements of the Sarbanes-Oxley Act, may strain our resources, increase our costs and distract management; and we may be unable to comply with these requirements in a timely or cost-effective manner.

As a public company with listed equity securities, we will need to comply with new laws, regulations and requirements, certain corporate governance provisions of the Sarbanes-Oxley Act of 2002, related regulations of the SEC and the requirements of the New York Stock Exchange (NYSE) with which we are not required to comply as a private company. Complying with these statutes, regulations and requirements will occupy a significant amount of time of our board of directors and management and will increase our costs and expenses. We will need to:

- institute a more comprehensive compliance function;
- design, establish, evaluate and maintain a system of internal controls over financial reporting in compliance with the requirements of Section 404 of the Sarbanes-Oxley Act of 2002 and the related rules and regulations of the SEC and the Public Company Accounting Oversight Board;
- comply with rules promulgated by the NYSE;
- prepare and distribute periodic public reports in compliance with our obligations under the federal securities laws;
- establish new internal policies, such as those relating to disclosure controls and procedures and insider trading;
- involve and retain to a greater degree outside counsel and accountants in the above activities; and
- establish an investor relations function.

In addition, we also expect that being a public company subject to these rules and regulations will require us to accept less director and officer liability insurance coverage than we desire or to incur substantial costs to obtain coverage. These factors could also make it more difficult for us to attract and retain qualified members of our board of directors, particularly to serve on our audit committee, and qualified executive officers. As a result, compliance with the requirements of the Sarbanes-Oxley Act could have a material adverse effect on our business.

Failure by us to achieve and maintain effective internal control over financial reporting in accordance with the rules of the SEC could harm our business and operating results and/or result in a loss of investor confidence in our financial reports, which could have a material adverse effect on our business and stock price.

We are in the process of evaluating our internal controls systems to allow management to report on, and our independent auditors to audit, our internal controls over financial reporting. We will be performing the system

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and process evaluation and testing (and any necessary remediation) required to comply with the management certification and auditor attestation requirements of Section 404 of the Sarbanes-Oxley Act of 2002. We will be required to comply with Section 404 for the year ending December 31, 2007. However, we cannot be certain as to the timing of completion of our evaluation, testing and remediation actions or the impact of the same on our operations. Furthermore, upon completion of this process, we may identify control deficiencies of varying degrees of severity under applicable SEC and Public Company Accounting Oversight Board rules and regulations that remain unremediated. As a public company, we will be required to report, among other things, control deficiencies that constitute a material weakness or changes in internal controls that, or that are reasonably likely to, materially affect internal controls over financial reporting. A material weakness is a significant deficiency or combination of significant deficiencies that results in more than a remote likelihood that a material misstatement of the annual or interim consolidated financial statements will not be prevented or detected. If we fail to implement the requirements of Section 404 in a timely manner, we might be subject to sanctions or investigation by regulatory authorities such as the SEC. In addition, failure to comply with Section 404 or the report by us of a material weakness may cause investors to lose confidence in our consolidated financial statements, and our stock price may be adversely affected as a result. If we fail to remedy any material weakness, our consolidated financial statements may be inaccurate, we may face restricted access to the capital markets and our stock price may be adversely affected.

We have no plans to pay dividends on our common stock, and therefore, you may not receive funds without selling your shares.

While we paid cash dividends of approximately $60.0 million and $27.6 million to our shareholders for tax purposes and, subject to forfeiture, to holders of unvested restricted stock in April and August 2006, respectively, we do not anticipate paying any additional cash dividends on our common stock in the foreseeable future. We currently intend to retain future earnings, if any, to finance the expansion of our business. Our future dividend policy is within the discretion of our board of directors and will depend upon various factors, including our business, financial condition, results of operations, capital requirements and investment opportunities.

We are a controlled company within the meaning of NYSE rules and, as a result, we will qualify for, and may rely on, exemptions from certain corporate governance requirements.

Because Harold G. Hamm will beneficially own in excess of 50% of our outstanding shares of common stock after the completion of this offering, he will be able to control the composition of our board of directors and direct our management and policies. We also will be deemed to be a controlled company under the rules of the NYSE. Under these rules, we are not required to comply with certain corporate governance requirements of the NYSE, including:

- the requirement that a majority of our board of directors consist of independent directors;

- the requirement that we have a nominating/corporate governance committee that is composed entirely of independent directors with a written charter addressing the committee s purpose and responsibilities; and

- the requirement that we have a compensation committee that is composed entirely of independent directors with a written charter addressing the committee s purpose and responsibilities.

Following this offering, we may utilize some or all of these exemptions. Accordingly, you may not have the same protections afforded to shareholders of companies that are subject to all of the corporate governance requirements of the NYSE. Mr. Hamm s significant ownership interest could adversely affect investors perceptions of our corporate governance.

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Provisions in our organizational documents and under Oklahoma law could delay or prevent a change in control of our company, which could adversely affect the price of our common stock.

We are an Oklahoma corporation. The existence of some provisions in our organizational documents, which we will amend and restate prior to the closing of this offering, and under Oklahoma law could delay or prevent a change in control of our company, which could adversely affect the price of our common stock. The provisions in our amended and restated certificate of incorporation and bylaws that could delay or prevent an unsolicited change in control of our company include a staggered board of directors, board authority to issue preferred stock and advance notice provisions for director nominations or business to be considered at a shareholder meeting. See Description of Capital Stock Anti-Takeover Effects of Provisions of Our Certificate of Incorporation and Bylaws and of Oklahoma Law.

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Use of Proceeds

We will not receive any proceeds from the sale of the shares of common stock by the selling shareholder. We estimate that the selling shareholder will receive net proceeds of approximately $ million from the sale of the shares of our common stock in this offering based upon the assumed initial public offering price of $ per share, after deducting underwriting discounts. We will pay all expenses relating to the selling shareholder s sale of common stock in this offering, other than underwriting discounts. If the underwriters overallotment option to purchase additional shares is exercised in full, we estimate that the selling shareholder s net proceeds will be approximately $ million.

Dividend Policy

We paid cash dividends of approximately $60.0 million and $27.6 million to our shareholders for tax purposes and, subject to forfeiture, to holders of unvested restricted stock in April and August 2006, respectively. In connection with the completion of this offering, we will convert from a subchapter S-corporation to a subchapter C-corporation, and we do not anticipate paying any additional cash dividends on our common stock in the foreseeable future. We currently intend to retain future earnings, if any, to finance the expansion of our business. Our future dividend policy is within the discretion of our board of directors and will depend upon various factors, including our results of operations, financial condition, capital requirements and investment opportunities.

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Capitalization

The following table shows our capitalization as of September 30, 2006:

- on a historical basis; and

- on a pro forma basis to reflect our conversion, concurrent with the closing of this offering, from a subchapter S-corporation to a subchapter C-corporation, reclassification of equity compensation accruals, the effect of an 11 for 1 stock split to be effected as a stock dividend prior to the consummation of this offering and other transactions for which pro forma presentation is necessary in conjunction with this offering.

We derived this table from, and it should be read in conjunction with and is qualified in its entirety by reference to, the historical consolidated financial statements and the accompanying notes included elsewhere in this prospectus. You should read this information in conjunction with these consolidated financial statements and Management s Discussion and Analysis of Financial Condition and Results of Operations.

	As of September 30, 2006	
	Historical	**Pro forma**
	(in thousands)	
Cash and cash equivalents	$ 4,456	$ 4,456
Long-term debt, including current maturities	160,000	160,000
Shareholders equity:		
Common stock, $.01 par value; 20,000,000 shares historical, 500,000,000 shares pro forma authorized, 14,457,314 shares historical, 159,030,454 pro forma issued and outstanding(1)	144	1,590
Additional paid-in capital(1)(2)	27,087	239,648
Retained earnings(2)(3)	418,972	65,140
Accumulated other comprehensive loss, net of taxes	79	79
Total shareholders equity	446,282	306,457
Total capitalization	$ 606,282	$ 466,457

(1) Reflects reclassification of $1.4 million from additional paid-in capital to common stock in order to adjust for the 11 for 1 stock split to be effected as a stock dividend in connection with the consummation of this offering.

(2) Pro forma adjustments reflect reclassification of the liability for equity compensation to additional paid-in capital, compensation expense as described in (3) below, expensing offering costs not already recognized in historical results, a charge to operations to recognize deferred taxes upon our conversion from a non-taxable subchapter S-corporation to a taxable subchapter C-corporation, the reclassification described in (1) above, and reclassification of undistributed earnings generated during the period of time we were organized as a subchapter S-corporation to additional paid-in capital in connection with our conversion

to a subchapter C-corporation.

(3) Reflects a pro forma adjustment to recognize compensation expense for the difference between the formula-derived value at which compensation expense was recorded and the initial public offering price of $, the midpoint of the range set forth on the cover page of this prospectus.

The following table reconciles historical additional paid-in capital and retained earnings to the pro forma amounts:

	Additional Paid-In Capital	**Retained Earnings**
	(in thousands)	
Historical	$ 27,087	$ 418,972
Reclassification of liability for equity compensation	13,231	
Compensation expense		
Offering costs		(176)
Deferred taxes on C-corporation conversion		(152,880)
Reclassification as described in (1) above	(1,446)	
Reclassification of undistributed earnings	200,776	(200,776)
Pro forma	$ 239,648	$ 65,140

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Dilution

Dilution is the amount by which the offering price paid by purchasers of common stock sold in this offering will exceed the net tangible book value per share of common stock after the offering. As of September 30, 2006, our net tangible book value was $446.3 million, or $2.81 per share of common stock. Purchasers of common stock in this offering will experience substantial and immediate dilution in net tangible book value per share of common stock for financial accounting purposes, as illustrated in the following table:

Assumed initial public offering price per share		$
Net tangible book value per share as of September 30, 2006	$ 2.81	
Dilution in net tangible book value per share to new investors		$

The average price per share at which our existing shareholders purchased shares of our common stock was $0.17 as compared to the assumed initial public offering price per share of $ paid by new investors.

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Selected Historical and Pro Forma

Consolidated Financial Information

This section presents our selected historical and pro forma consolidated financial data. The selected historical consolidated financial data presented below is not intended to replace our historical consolidated financial statements.

The following historical consolidated financial data, as it relates to each of the fiscal years ended December 31, 2001 through 2005, has been derived from our audited historical consolidated financial statements for such periods. The following historical financial data, as it relates to each of the nine month periods ended September 30, 2005 and 2006, has been derived from our unaudited historical consolidated financial statements for such periods. You should read the following selected historical consolidated financial data in connection with Capitalization, Management s Discussion and Analysis of Financial Condition and Results of Operations and our historical consolidated financial statements and related notes included elsewhere in this prospectus. The selected historical consolidated results are not necessarily indicative of results to be expected in future periods.

The selected pro forma financial data reflect the tax effects of our conversion, concurrent with the closing of this offering, from a subchapter S-corporation to a subchapter C-corporation and the earnings per share impact of our 11 for 1 stock split to be effected in the form of a stock dividend concurrent with the closing of this offering.

	Year ended December 31,					Nine months ended September 30,	
	2001	2002	2003	2004	2005	2005	2006
	(in thousands, except per share amounts)						
Statement of operations data:							
Revenues:							
Oil and natural gas sales	$ 112,170	$ 108,752	$ 138,948	$ 181,435	$ 361,833	$ 251,603	$ 358,004
Crude oil marketing and trading(1)	245,872	152,092	169,547	226,664			
Oil and natural gas service operations	6,047	5,739	9,114	10,811	13,931	10,447	11,735
Total revenues	364,089	266,583	317,609	418,910	375,764	262,050	369,739
Operating costs and expenses:							
Production expense	31,859	32,299	40,821	43,754	52,754	38,256	46,160
Production tax	8,385	7,729	10,251	12,297	16,031	10,930	16,610
Exploration expense	15,863	10,229	17,221	12,633	5,231	2,493	9,085
Crude oil marketing and trading(1)	245,003	152,718	166,731	227,210			
Oil and gas service operations	2,820	3,485	5,641	6,466	7,977	5,663	6,644
Depreciation, depletion, amortization and accretion	25,659	29,010	40,256	38,627	49,802	34,584	46,376
Property impairments	10,113	25,686	8,975	11,747	6,930	5,760	9,080
General and administrative(2)	6,199	8,668	9,604	12,400	31,266	24,847	19,814
(Gain) loss on sale of assets	(3,423)	(223)	(589)	150	(3,026)	(2,906)	(292)

Total operating costs and expenses	$ 342,478	$ 269,601	$ 298,911	$ 365,284	$ 166,965	$ 119,627	$ 153,477

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	Year ended December 31,					Nine months ended September 30,	
	2001	2002	2003	2004	2005	2005	2006
	(in thousands, except per share amounts)						
Income (loss) from operations	$ 21,611	$ (3,018)	$ 18,698	$ 53,626	$ 208,799	$ 142,423	$ 216,262
Other income (expense)							
Interest expense	(15,324)	(18,216)	(19,761)	(23,617)	(14,220)	(11,109)	(8,522)
Loss on redemption on bonds				(4,083)			
Other	645	912	295	890	867	498	1,230
Total other income (expense)	(14,679)	(17,304)	(19,466)	(26,810)	(13,353)	(10,611)	(7,292)
Income (loss) from continuing operations before income taxes	6,932	(20,322)	(768)	26,816	195,446	131,812	208,970
Provision (benefit) for income taxes(3)					1,139	1,139	(132)
Income (loss) from continuing operations	6,932	(20,322)	(768)	26,816	194,307	130,673	209,102
Discontinued operations(4)	4,735	290	946	1,680			
Loss on sale of discontinued operations(4)				(632)			
Income (loss) before cumulative effect of change in accounting principle	11,667	(20,032)	178	27,864	194,307	130,673	209,102
Cumulative effect of change in accounting principle(5)			2,162				
Net income (loss)	$ 11,667	$ (20,032)	$ 2,340	$ 27,864	$ 194,307	$ 130,673	$ 209,102
Basic earnings (loss) per share:							
From continuing operations	$ 0.48	$ (1.41)	$ (0.05)	$ 1.87	$ 13.52	$ 9.09	$ 14.55
From discontinued operations(4)	0.33	0.02	0.06	0.11			
Loss on sale of discontinued operations(4)				(0.04)			
Before cumulative effect of change in accounting principle	0.81	(1.39)	0.01	1.94	13.52	9.09	14.55
Cumulative effect of change in accounting principle			0.15				
Net income (loss) per share	$ 0.81	$ (1.39)	$ 0.16	$ 1.94	$ 13.52	$ 9.09	$ 14.55
Shares used in basic earnings (loss) per share	14,369	14,369	14,369	14,369	14,369	14,369	14,369
Diluted earnings (loss) per share:							
From continuing operations	$ 0.48	$ (1.41)	$ (0.05)	$ 1.85	$ 13.42	$ 9.00	$ 14.40
From discontinued operations(4)	0.33	0.02	0.06	0.12			
Loss on sale of discontinued operations(4)				(0.04)			
Before cumulative effect of change in accounting principle	0.81	(1.39)	0.01	1.93	13.42	9.00	14.40
Cumulative effect of change in accounting principle			0.15				

Net income (loss) per share	$ 0.81	$ (1.39)	$ 0.16	$ 1.93	$ 13.42	$ 9.00	$ 14.40
Shares used in diluted earnings (loss) per share	14,393	14,369	14,369	14,476	14,482	14,522	14,516

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	Year ended December 31,					Nine months ended September 30,	
	2001	2002	2003	2004	2005	2005	2006
	(in thousands, except per share amounts)						
Pro forma C-corporation and stock split data:							
Income (loss) from continuing operations before income taxes	$ 6,932	$ (20,322)	$ (768)	$ 26,816	$ 195,446	$ 131,812	$ 208,970
Pro forma provision (benefit) for income taxes attributable to operations	2,634	(7,722)	(292)	10,190	74,269	50,089	79,409
Pro forma income (loss) from operations after tax	4,298	(12,600)	(476)	16,626	121,177	81,723	129,561
Discontinued operations net of tax(4)	2,936	180	587	1,042			
Loss on sale of discontinued operations(4)				(392)			
Cumulative effect of change in accounting principle net of tax			1,340				
Pro forma net income (loss)	$ 7,234	$ (12,420)	$ 1,451	$ 17,276	$ 121,177	$ 81,723	$ 129,561
Pro forma basic earnings (loss) per share	$ 0.05	$ (0.08)	$ 0.01	$ 0.11	$ 0.77	$ 0.52	$ 0.82
Pro forma diluted earnings (loss) per share	0.05	(0.08)	0.01	0.11	0.76	0.51	0.81
Other financial data:							
Cash dividends per share:	$	$	$	$ 1.04	$ 0.14	$ 0.14	$ 6.06
EBITDAX (6)	78,626	63,288	88,750	116,498	285,344	198,089	287,009
Net cash provided by operations	63,413	46,997	65,246	93,854	265,265	161,974	288,999
Net cash used in investing	(106,384)	(113,295)	(108,791)	(72,992)	(133,716)	(83,295)	(219,436)
Net cash provided by (used in) financing	43,045	61,593	43,302	(7,245)	(141,467)	(85,686)	(71,162)
Capital expenditures	111,023	113,447	114,145	94,307	144,800	94,179	221,288
Balance sheet data (at period end):							
Cash and cash equivalents	$ 7,225	$ 2,520	$ 2,277	$ 15,894	$ 6,014	$ 8,927	$ 4,456
Property and equipment, net	317,331	367,903	439,432	434,339	509,393	476,019	672,415
Total assets	354,485	406,677	484,988	504,951	600,234	575,594	782,896
Long-term debt, including current maturities	183,395	247,105	290,920	290,522	143,000	196,000	160,000
Shareholders equity	135,113	115,081	116,932	130,385	324,730	261,098	446,282

(1) Crude oil marketing and trading captions consist of our marketing activities under which crude oil production was sold at the wellhead and transported to a local hub where we purchased the barrels back to exchange at Cushing, Oklahoma in order to minimize pricing differentials with the NYMEX oil futures contract. We adopted Emerging Issues Task Force (EITF) 04-13 on January 1, 2005, which allowed certain purchase and sales transactions with the same counterparty to be combined and accounted for as a single transaction under the guidance of Accounting Principles Board Opinion No. 29. In 2005, we netted $39.8 million of crude oil marketing and trading revenues and $39.7 million of crude oil marketing and trading expenses under oil and natural gas sales. Prior to the adoption of EITF 04-13, we presented crude oil marketing and trading revenues and expenses gross under the guidance provided by EITF 99-19, Reporting Revenues Gross as a Principal and/or Net as an Agent. Effective March 2005, we ceased marketing our crude oil production under these arrangements. Thereafter, we have sold our crude oil at the wellhead. Certain of these sales have been to our affiliates, as described under Certain Relationships and Related Party Transactions.

(2) We have included stock-based compensation of $0.0 million, $0.2 million, $0.2 million, $2.0 million, $13.7 million, $12.3 million and $5.0 million in general and administrative expenses for the years ended December 31, 2001, 2002, 2003, 2004 and 2005 and for the nine months ended September 30, 2005 and 2006, respectively. Our stock based compensation plan requires us to purchase vested shares at the employee s request based on an internally calculated value of our stock. Amounts noted herein represent the increase in our liability associated with our purchase obligation. The valuation is based on the book value of our shareholders equity adjusted for our PV-10 as of each calendar quarter. Our requirement to purchase vested shares will be eliminated once we begin

reporting under Section 12 of the Exchange Act. As a result of this change, we will recognize a charge of approximately $ upon completion of this offering, assuming an offering price at the midpoint of the range set forth on the cover page of this prospectus. See Capitalization.

(3) Properties owned by us at May 31, 1997, the date we converted into a subchapter S-corporation from a subchapter C-corporation, may be subject to federal taxation if sold for an amount in excess of the then tax basis for the sold assets. During 2005, we incurred federal taxes due to the sale of assets acquired prior to May 31, 1997. The benefit recorded during 2006 reflects a change in estimate of the original provision recorded for federal taxes incurred.

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(4) In July 2004, we sold all of the outstanding stock in Continental Gas, Inc., a wholly owned subsidiary, to our shareholders. The Continental Gas, Inc. assets included seven gas gathering systems and three gas-processing plants. These assets represented our entire gas gathering, marketing and processing segment. We have accounted for these operations as discontinued operations.

(5) We adopted Statement of Financial Accounting Standards No. 143, Accounting for Asset Retirement Obligations and recorded the cumulative effect of the change in accounting principle on January 1, 2003.

(6) EBITDAX represents earnings before interest expense, income taxes (when applicable), depreciation, depletion, amortization and accretion, property impairments, exploration expense and non-cash compensation expense. EBITDAX is not a measure of net income or cash flow as determined by generally accepted accounting principles (GAAP). EBITDAX should not be considered as an alternative to, or more meaningful than, net income or cash flow as determined in accordance with GAAP or as an indicator of a company s operating performance or liquidity. Certain items excluded from EBITDAX are significant components in understanding and assessing a company s financial performance, such as a company s cost of capital and tax structure, as well as the historic costs of depreciable assets, none of which are components of EBITDAX. Our computations of EBITDAX may not be comparable to other similarly titled measures of other companies. We believe that EBITDAX is a widely followed measure of operating performance and may also be used by investors to measure our ability to meet future debt service requirements, if any. Our credit facility requires that we maintain a total debt to EBITDAX ratio of no greater than 3.75 to 1 on a rolling four-quarter basis. Our credit facility defines EBITDAX consistently with the definition of EBITDAX utilized and presented by us. At December 31, 2005 and September 30, 2006, this ratio was approximately 0.5 to 1 and 0.4 to 1, respectively. The following table represents a reconciliation of our net income (loss) to EBITDAX:

	Year ended December 31,					Nine months ended September 30,	
	2001	2002	2003	2004	2005	2005	2006
						(unaudited)	
	(in thousands)						
Net income (loss)	$ 11,667	$ (20,032)	$ 2,340	$ 27,864	$ 194,307	$ 130,673	$ 209,102
Interest expense	15,324	18,216	19,761	23,617	14,220	11,109	8,522
Provision (benefit) for income taxes					1,139	1,139	(132)
Depreciation, depletion, amortization and accretion	25,659	29,010	40,256	38,627	49,802	34,584	46,376
Property impairments	10,113	25,686	8,975	11,747	6,930	5,760	9,080
Exploration expense	15,863	10,229	17,221	12,633	5,231	2,493	9,085
Equity compensation		179	197	2,010	13,715	12,331	4,976
EBITDAX	$ 78,626	$ 63,288	$ 88,750	$ 116,498	$ 285,344	$ 198,089	$ 287,009

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Management s Discussion and Analysis of

Financial Condition and Results of Operations

The following discussion should be read in conjunction with our historical consolidated financial statements and notes, as well as the selected historical consolidated financial data included elsewhere in this prospectus.

Overview

We are engaged in oil and natural gas exploration and exploitation activities in the Rocky Mountain, Mid-Continent and Gulf Coast regions of the United States. Crude oil comprised 85% of our 116.7 MMBoe of estimated proved reserves as of December 31, 2005 and 79% of our 7,209 MBoe of production for the year then ended. We seek to operate wells in which we own an interest, and we operated wells that accounted for 97% of our PV-10 and 1,213 of our 1,434 gross wells as of December 31, 2005. By controlling operations, we are able to more effectively manage the cost and timing of exploration and development of our properties, including the drilling and fracture stimulation methods used.

Our business strategy has focused on reserve and production growth through exploration and development. For the three-year period ended December 31, 2005, we added 55,385 MBoe of proved reserves through extensions and discoveries, compared to 426 MBoe added through purchases. During this period, our production increased from 5,255 MBoe in 2003 to 7,209 MBoe in 2005. An aspect of our business strategy has been to acquire large undeveloped acreage positions in new or developing locations. As of December 31, 2005, we held approximately 1,086,000 gross (646,000 net) undeveloped acres, including 356,000 net acres in the Bakken field in Montana and North Dakota and 72,000 net acres in the New Albany Shale, Lewis Shale, Floyd Shale and Woodford Shale projects. As an early entrant in new or emerging plays, our costs to acquire undeveloped acreage have generally been less than those of later entrants into a developing play. As an example of the cost advantage of entering a play early, our per acre costs for our lease acquisitions in the North Dakota Bakken field during 2003 and 2004 were approximately 80% lower than the per acre costs paid by third parties and by us in the federal and state lease auctions for acreage near our holdings in that area during 2005. However, as an early entrant, we are exposed to the risk that the value of our undeveloped acreage is diminished by unsuccessful drilling results.

How We Evaluate Our Operations

We use a variety of financial and operational measures to assess our performance. Among these measures are the following:

(1) Volumes of oil and natural gas produced;

(2) Oil and natural gas prices realized;

(3) Volumetric operating and administrative costs; and

(4) EBITDAX.

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Volumes of Oil and Natural Gas Produced

For our operated properties in the Red River units and the Bakken field, we receive daily production estimates that enable us to monitor our production on a current basis. We believe the timeliness of this information and the control we exert as an operator enables us to respond promptly to production difficulties. Over the past three years our equivalent production volumes have increased 37% or 1,954 MBoe due primarily to a 65% increase in oil production. The following table presents our production volumes for each of the three years ended December 31, 2005 and the nine months ended September 30, 2005 and 2006:

	Year Ended December 31,			Three-year period		Nine months ended September 30,		Nine-month period	
	2003	2004	2005	Volume increase (decrease)	Percent increase (decrease)	2005	2006	Volume increase (decrease)	Percent increase (decrease)
MBbls	3,463	3,688	5,708	2,245	65%	4,045	5,454	1,409	35%
MMcf	10,751	8,794	9,006	(1,745)	(16%)	6,748	6,755	7	%
MBoe	5,255	5,154	7,209	1,954	37%	5,170	6,580	1,410	27%

The increase in our production has been the result of a favorable response to additional field development and enhanced recovery efforts in our Red River units coupled with exploration and development within our other producing areas, primarily the Montana Bakken field.

Oil and Natural Gas Prices Realized

We market our oil and natural gas production to a variety of purchasers based on regional pricing. A significant portion of our oil and natural gas production has been marketed to affiliates as discussed under Certain Relationships and Related Party Transactions.

The following table presents the NYMEX oil and natural gas prices, our realized oil and natural gas prices, exclusive of the effects of hedging, and the differences for each of the three years ended December 31, 2005 and the nine months ended September 30, 2005 and 2006. The NYMEX oil price was determined each month as the calendar month average of the prompt NYMEX crude oil futures contract price and, the NYMEX natural gas price, as the average of the last three trading days of the prompt NYMEX natural gas futures contract price. The NYMEX natural gas futures contract price is quoted on an MMBtu basis. For purposes of comparison, in the table below the NYMEX natural gas price was converted to an Mcf basis at a one-to-one conversion:

Year ended December 31,

				Nine months ended September 30,	
	2003	2004	2005	2005	2006
NYMEX oil price ($/Bbl)	$ 31.08	$ 41.95	$ 57.69	$ 56.74	$ 68.60
Realized oil price before hedging ($/Bbl)	28.88	38.85	52.45	51.90	58.05
Difference	$ 2.20	$ 3.10	$ 5.24	$ 4.84	$ 10.55
NYMEX natural gas price ($/Mcf)	5.33	6.10	8.54	7.10	7.47
Realized natural gas price ($/Mcf)	4.55	5.06	6.93	6.17	6.22
Difference	$ 0.78	$ 1.04	$ 1.61	$ 0.93	$ 1.25

The differences are subject to variability due to quality and location pricing fluctuations caused by localized supply and demand fundamentals and transportation availability. The increase in the difference between the NYMEX oil price and our realized oil price for the nine months ended September 30, 2006 was attributable to

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higher oil imports and production in the Rocky Mountain region, lower demand by local Rocky Mountain refineries due to downtime for maintenance and reduced seasonal demand for gasoline and downstream transportation capacity constraints. We are unable to predict when, or if, the difference will revert back to 2005 levels.

Our revenues and net income are sensitive to oil and natural gas prices. A $1.00 per Bbl change in realized oil prices would change our reported 2005 revenues and net income by approximately $5.7 million and $5.4 million, respectively. A comparable change during the nine months ended September 30, 2005 and 2006 would change our reported revenue by $4.0 million and $5.4 million, respectively, and our net income by $3.9 million and $5.2 million, respectively. Similarly, a $0.10 per Mcf change in realized natural gas prices would change our reported 2005 revenues and net income by approximately $901,000 and $852,000, respectively. A comparable change during the nine months ended September 30, 2005 and 2006 would change our reported revenue by $675,000 and $676,000, respectively, and our net income by $645,000 and $644,000, respectively.

For the years ended December 31, 2003 and 2004, we realized oil hedging losses of $10.1 million and $6.4 million, respectively. As a result of our limited bank borrowings and strong operational cash flows, we did not enter into any hedges for our 2005 production, and we do not currently have plans to hedge any of our 2006 production.

Volumetric Operating and Administrative Costs

Two other measures that we monitor and analyze are production expense per Boe sold and general and administrative expense per Boe sold. We believe these are important measures because they are indicators of operating cost efficiency.

The following table presents our production expense and general and administrative expense, inclusive of stock-based compensation, per Boe sold for each of the three years ended December 31, 2005 and the nine months ended September 30, 2005 and 2006:

	Year ended December 31,			Nine months ended September 30,	
	2003	**2004**	**2005**	**2005**	**2006**
Production expense ($/Boe)	$ 7.77	$ 8.49	$ 7.32	$ 7.40	$ 7.03
General and administrative expense ($/Boe)	1.83	2.41	4.34	4.81	3.02

Our per unit production expense increased during 2004 in connection with our enhanced recovery project in the Red River units which initially lowered volumes and increased production expense. Our per unit production expense declined in 2005 and 2006 as we are experiencing higher production volumes due to continued drilling and higher production in conjunction with the completion of the enhanced recovery program. Generally as production increases, we will see increased production expense due to additional well costs, such as lifting and workover costs, and additional personnel costs although these costs may be lower on a volumetric basis due to higher production. The increase in our per unit general and administrative expense in 2005 was primarily due to higher compensation expense. The largest component of the increase was equity compensation, which contributed $0.2 million, $2.0 million and $13.7 million during the years ended December 31, 2003, 2004 and 2005, respectively, and $12.3 million and $5.0 million during the nine months ended September 30, 2005 and 2006, respectively. The annual increases in equity compensation were attributable to additional equity grants and a higher per share valuation resulting from annual increases in our PV-10. The decline in equity compensation between the comparable periods was attributable to a lower per share valuation resulting from a decline in our PV-10 valuation due to lower oil and natural gas commodity prices as of September 30, 2006 compared to December 31, 2005. We compete with other companies for personnel, particularly in the operational and technical (engineering and geologic) aspects of our business. To remain competitive, we compare the compensation we pay our employees to that of our competitors through surveys, employee feedback and other means. We have experienced higher compensation expense due to competitive pressures, normal merit increases and incentive compensation. Our incentive compensation has increased due to improving operating results. During 2004, we recorded incentive compensation of $413,000 compared to $4.0 million in 2005.

EBITDAX

We calculate and define EBITDAX as net income before interest expense, income taxes (when applicable), depreciation, depletion, amortization and accretion, property impairments, exploration expense and non-cash compensation expense. EBITDAX is used as a financial measure by our management team and by other users of our consolidated financial statements such as our commercial bank lenders, investors, research analysts and others to assess:

- Our operating performance and return on capital in comparison to other independent exploration and production companies, without regard to financial or capital structure;
- The financial performance of our assets and valuation of the entity without regard to financing methods, capital structure or historical cost basis; and
- Our ability to generate cash sufficient to pay interest costs and support our indebtedness.

The following table presents our EBITDAX for each of the three years ended December 31, 2005 and the nine months ended September 30, 2005 and 2006 (in thousands):

	Year ended December 31,			Nine months ended September 30,	
	2003	2004	2005	2005	2006
EBITDAX	$ 88,750	$ 116,498	$ 285,344	$ 198,089	$ 287,009

EBITDAX is a financial measure that is reported to our lenders each calendar quarter. Our credit facility requires that our total debt to EBITDAX ratio be no greater that 3.75 to 1 on a rolling four quarter basis. This ratio was 0.5 to 1 at December 31, 2005 and 0.4 to 1 at September 30, 2006. Our credit facility defines EBITDAX consistently with the definition of EBITDAX utilized and presented by us. EBITDAX is not and should not be considered as an alternative to net income, operating income, cash flows from operating activities or any other measure of financial performance presented in accordance with GAAP. For a reconciliation of our consolidated net income (loss) to EBITDAX, see footnote (6) to Summary Historical and Pro Forma Consolidated Financial Data.

Recent Events

Payment of Cash Dividends. On April 13 and August 15, 2006, we paid cash dividends of approximately $60.0 million and $27.6 million, respectively, to our shareholders for tax purposes and, subject to forfeiture, to holders of unvested restricted stock. In connection with the completion of this offering, we will convert from a subchapter S-corporation to a subchapter C-corporation, and we do not anticipate paying any additional cash dividends on our common stock in the foreseeable future.

NYMEX and Related Oil Price Differential. The difference between the calendar month average of the NYMEX crude oil prices and our realized crude oil prices increased in the Rocky Mountain region during the nine months ended September 30, 2006 compared to the year ended December 31, 2005. For the year ended December 31, 2005, the average company-wide difference was $5.24 per Bbl. The company-wide difference for the nine months ended September 30, 2006 was $10.55 per Bbl. Factors affecting the difference include higher

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Canadian oil imports, production in the region, lower demand by local refineries due to downtime for maintenance and reduced seasonal demand for gasoline and downstream transportation capacity constraints. We are unable to predict when, or if, the difference will revert back to 2005 levels.

Acreage Acquisition. In April 2006, we purchased a 50% interest in 135,000 acres in the Marfa Basin in Presidio and Brewster Counties, Texas as well as overriding royalty interests covering a portion of the acreage for approximately $7 million. We plan to re-enter a well on the acreage to test the Woodford and Barnett equivalent shales during the second half of 2006.

North Dakota Bakken Joint Venture. In June 2006, we entered into an agreement with ConocoPhillips Company to form an area of mutual interest (AMI) within Dunn, McKenzie, Mountrail and Williams Counties, North Dakota and jointly drill wells to test the Bakken formation. Within the AMI, we own approximately 97,000 net acres. Initial wells proposed under the agreement establish exploration blocks covering the 1,280-acre spacing unit for the initial well and two adjacent 1,280-acre spacing units. Each party has the right to acquire from the other party an undivided 50% interest in the exploration block acreage owned by the other party at $500 per net acre. ConocoPhillips Company has proposed and we have agreed to participate in the initial three wells to be drilled under the agreement. As of November 14, 2006, one well was producing, one well was drilled and awaiting completion and one well was being drilled.

2007 Capital Expenditure Budget. On November 7, 2006, our Board of Directors approved a capital expenditure budget of $400 million for calendar year 2007 allocated as follows:

	Wells planned for drilling	Capital expenditures (in millions)
Rocky Mountain:		
Red River units	41	$ 123
Bakken field	65	113
Other	24	31
Mid-Continent	54	62
Gulf Coast	3	4
Total exploration and development drilling	187	$ 333
Capital facilities		28
Workover / recompletion		9
Land costs		19
Seismic		7
Vehicles, computers & other equipment		4
Total		$ 400

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Results of Operations

The following tables present selected financial and operating information for each of the three years ended December 31, 2005 and the nine months ended September 30, 2005 and 2006:

	Year ended December 31,			Nine months ended September 30,	
	2003	2004	2005	2005	2006
	(in thousands, except price data)				
Oil and natural gas sales	$ 138,948	$ 181,435	$ 361,833	$ 251,603	$ 358,004
Total revenues(1)	317,609	418,910	375,764	262,050	369,739
Operating costs and expenses(1)	298,911	365,284	166,965	119,627	153,477
Other income (expense)	(19,466)	(26,810)	(13,353)	(10,611)	(7,292)
Income (loss) from continuing operations before income taxes	(768)	26,816	195,446	131,812	208,970
Provision for income taxes			1,139	1,139	(132)
Income (loss) from continuing operations	(768)	26,816	194,307	130,673	209,102
Discontinued operations	946	1,680			
Loss on sale of discontinued operations		(632)			
Cumulative effect of a change in accounting principle	2,162				
Net income	$ 2,340	$ 27,864	$ 194,307	$ 130,673	$ 209,102
Production volumes:					
Oil (MBbl)(2)	3,463	3,688	5,708	4,045	5,454
Natural gas (MMcf)	10,751	8,794	9,006	6,748	6,755
Oil equivalents (MBoe)	5,255	5,154	7,209	5,170	6,580
Average prices(2):					
Oil, without hedges ($/Bbl)	$ 28.88	$ 38.85	$ 52.45	$ 51.90	$ 58.05
Oil, with hedges ($/Bbl)	25.98	37.12	52.45	51.90	58.05
Natural gas ($/Mcf)	4.55	5.06	6.93	6.17	6.22
Oil equivalents, without hedges ($/Boe)	28.35	36.45	50.19	48.67	54.50
Oil equivalents, with hedges ($/Boe)	26.44	35.20	50.19	48.67	54.50

(1) Revenues for 2003 and 2004 include $169,547,000 and $226,664,000, respectively, for crude oil marketing and trading and operating expenses include $166,731,000 and $227,210,000, respectively, for crude oil marketing and trading.

(2) Oil sales volumes are 10 MBbls less than oil production volumes for the nine months ended September 30, 2006. Average prices have been calculated using sales volumes.

Nine Months Ended September 30, 2006 Compared to the Nine Months Ended September 30, 2005

Revenues.

Oil and natural gas sales. Oil and natural gas sales for the nine months ended September 30, 2006 were $358.0 million, a 42% increase over sales of $251.6 million for the comparable period of 2005. Increased sales resulted from higher sales volumes, which increased 27%, and an increase of $5.83 in our realized price per Boe from $48.67 to $54.50. During the nine months ended September 30, 2006, we experienced an increase in the differential between NYMEX prices and our realized crude oil prices. The differential per Bbl for the nine months ended September 30, 2006 was $10.55 as compared to $4.84 for the comparable period of 2005. We realized a crude oil differential in September 2006 of $8.64 per Bbl compared to a 2006 high of $14.25 per Bbl in March. Among the factors contributing to the higher differentials were higher Canadian oil imports, increases in production in the Rocky Mountain region, refinery downtime in the Rocky Mountain region, downstream

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transportation capacity constraints, and reduced seasonal demand for gasoline. We are unable to predict when and if the differential will revert back to 2005 levels.

The following tables reflect our production by product and region for the periods presented.

	Nine Months ended September 30,				Volume increase (decrease)	Percent increase (decrease)
	2005		2006			
	Volume	Percent	Volume	Percent		
Oil (MBbl)	4,045	78%	5,454	83%	1,409	35%
Natural Gas (MMcf)	6,748	22%	6,755	17%	7	0%
Total (MBoe)	5,170	100%	6,580	100%	1,410	27%

	Nine Months ended September 30,				Volume increase (decrease)	Percent increase (decrease)
	2005		2006			
	Mboe	Percent	Mboe	Percent		
Rocky Mountain(1)	3,802	73%	5,195	79%	1,393	37%
Mid-Continent	1,019	20%	1,103	17%	84	8%
Gulf Coast	349	7%	282	4%	(67)	(19%)
Total (MBoe)	5,170	100%	6,580	100%	1,410	27%

(1) 2006 oil sales volumes are 10 MBbls less than oil production volumes for the nine months ended September 30, 2006.

Oil volumes increased 35% during the nine months ended September 30, 2006 in comparison to the nine months ended September 30, 2005. Production increases in the Bakken field contributed incremental volumes of 659 MBbls in excess of 2005 levels, and the Red River units contributed 671 MBbls of incremental production over 2005 levels. Our initial production commenced in the Bakken field in August 2003 and has increased since that time, as we have continued exploration and development activities within the field. Favorable results from the enhanced recovery program and additional field development have been the primary contributors to production growth in the Red River units.

Oil and Natural Gas Service Operations. Our oil and natural gas service operations consist primarily of sales of high-pressure air and the treatment and sale of lower quality crude oil, or reclaimed oil. We initiated the sale of high-pressure air from our Red River units to a third party in 2004 and recorded revenues of $2.2 million for the first nine months of 2006 compared to $1.9 million for the first nine months of 2005. Higher prices for reclaimed oil sold from our central treating unit in 2006 increased oil and natural gas service operations revenues by $1.6 million to $7.5 million. Associated oil and natural gas service operations expenses increased $0.9 million to $6.6 million during the nine months ended September 30, 2006 from $5.7 million during the 2005 period due mainly to an increase in the costs of purchasing and treating oil for resale.

Operating Costs and Expenses

Production Expense and Tax. Production expense increased $7.9 million or 21% during the nine months ended September 30, 2006 to $46.2 million from $38.3 million during the nine months ended September 30, 2005. The increase in 2006 was due primarily to increases of $1.4 million in repairs, $1.3 million in energy and chemical costs, $0.6 million in outside operated well costs, $0.3 million in contract labor costs, $0.3 million in salt water disposal costs, $0.6 million increase in overhead costs, and $2.9 million in workovers.

Production taxes increased $5.7 million during the nine months ended September 30, 2006 to $16.6 million from $10.9 million during the comparable 2005 period. Production taxes increased $5.0 million in the Rocky Mountain region, $0.6 million in the Mid-Continent region and $0.1 million in the Gulf Coast region. Production tax as a percentage of oil and natural gas sales was 4.3% for the first nine months of 2005 compared to 4.6% for

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the first nine months of 2006. The production tax incentives we currently receive for horizontal wells in Montana will be reaching the end of the 18 month grace period for wells drilled in 2005 and our overall rate will begin to increase during the remainder of 2006.

On a unit of sales basis, production expense and production taxes were as follows:

On a Boe Basis	Nine Months ended September 30, 2005	Nine Months ended September 30, 2006	Percent increase (decrease)
Production expense ($/Boe)	$ 7.40	$ 7.03	(5)%
Production tax ($/Boe)	2.11	2.53	20%
Production expense and tax ($/Boe)	$ 9.51	$ 9.56	1%

Exploration Expense. Exploration expenses consist primarily of dry hole costs and exploratory geological and geophysical costs that are expensed as incurred. Exploration expenses increased $6.6 million in the first nine months of 2006 to $9.1 million due to an increase in dry hole expense of $5.0 million mostly in the Mid-Continent region and an increase in geological and seismic expenses of $1.5 million.

Depreciation, Depletion, Amortization and Accretion (DD&A.) DD&A on oil and gas properties increased $11.8 million in 2006 due to additional properties being added through our drilling program and corresponding increases in production. The DD&A rate on oil and gas properties for the first nine months of 2005 was $6.26 per Boe compared to $6.69 per Boe for the first nine months of 2006. Accretion expense of approximately $1.2 million is included in DD&A for the first nine months each of 2006 and 2005.

Property Impairments. Property impairments increased for the first nine months of 2006 by $3.3 million to $9.1 million compared to $5.8 million during the first nine months of 2005. Non-producing properties consist of undeveloped leasehold costs and costs associated with the purchase of certain proved undeveloped reserves. Individually significant non-producing properties are periodically assessed for impairment of value, and a loss is recognized at the time of impairment by providing an impairment allowance. Other non-producing properties are amortized on a composite method based on our estimated experience of successful drilling and the average holding period. Impairment of non-producing properties increased $0.3 million during the first nine months of 2006 to $3.8 million compared to $3.5 million for the first nine months of 2005.

Impairment expense for developed oil and gas properties were approximately $2.3 million during the nine months ended September 30, 2005 and $5.3 million during the nine months ended September 30, 2006. The increase in 2006 impairment expense resulted primarily from development well dry holes and properties where the associated field level reserves were not sufficient to recover capitalized drilling and completion costs.

General and Administrative Expense. General and administrative expense decreased primarily due to a $7.4 million decrease in equity compensation expense associated with restricted stock grants in the fourth quarter of 2005 and in 2006 under the 2005 long-term incentive plan.

The decrease in equity compensation expense was attributable to a lower per share value for our equity grants as a result of a decline in our PV-10 value due to lower oil and gas prices as of the September 30, 2006 compared to December 31, 2005. General and administrative expense was $3.02 per Boe for the first nine months of 2006 compared to $4.81 per Boe for the first nine months of 2005.

Gain on Sale of Assets. During the first nine months of 2005, we realized a gain of $6.2 million on the sale of oil and gas wells and a loss of $3.1 million on the termination of compressor capital leases which were the primary reasons for the net gain on sale of assets.

Interest Expense. Interest expense decreased 23% for the first nine months of 2006 attributable to lower average outstanding debt balance on our credit facility of $157.7 million compared to $201.2 million for the first

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nine months of 2005. The weighted average interest rate on our credit facility was 6.48% at September 30, 2006

compared to 5.65% at September 30, 2005. Additionally, in the 2005 period we had an outstanding balance due to our principal shareholder for $48.0 million which was paid in full during December 2005. We paid $2.2 million in interest on this note during the first nine months of 2005 at a rate of 6%.

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

Revenues

Oil and Natural Gas Sales. We generally market our production at the wellhead. Oil and natural gas sales increased $180.4 million or 99% to $361.8 million in 2005. The increase was attributable to higher production volumes and higher oil and natural gas prices. During 2004, our average wellhead oil price was $38.85 per Bbl and our wellhead natural gas price was $5.06 per Mcf, compared to $52.45 per Bbl for oil and $6.93 per Mcf for natural gas during 2005. The increases in our wellhead prices were due to general industry price escalations in our producing regions. Our oil sales in 2004 were reduced by a $6.4 million loss in our hedging activities. We did not hedge our production during 2005. The following tables reflect our production by product and region for the periods presented:

	Year ended December 31,				
	2004		2005		
	Volume	Percent	Volume	Percent	Percent increase
Oil (MBbl)	3,688	72%	5,708	79%	55%
Natural Gas (MMcf)	8,794	28%	9,006	21%	2%
Total (MBoe)	5,154	100%	7,209	100%	40%

	Year ended December 31,				
	2004		2005		
	MBoe	Percent	MBoe	Percent	Percent increase (decrease)
Rocky Mountain	3,279	64%	5,410	75%	65%
Mid-Continent	1,461	28%	1,361	19%	(7)%
Gulf Coast	414	8%	438	6%	6%
Total MBoe	5,154	100%	7,209	100%	40%

Production increases in our Bakken field and Red River units in the Rocky Mountain region of 1,226 MBoe and 1,051 MBoe, respectively, accounted for the growth in production for 2005. We commenced drilling our initial well in the Bakken field in May 2003 and completed it as a producing well in August 2003. Our well count in the Bakken field rose from 25 gross (14.5 net) wells at December 31, 2004 to 60 gross (34.2 net) wells at December 31, 2005. Favorable response to the enhanced recovery program was the primary factor in the production growth in the Red River units.

Crude Oil Marketing and Trading. During 2004 and the first three months of 2005, we purchased barrels back from certain of our wellhead purchasers downstream of the initial sales point to exchange at the Cushing, Oklahoma hub in order to minimize pricing differentials with the NYMEX oil futures contract. In 2005, revenues of $39.8 million and expenses of $39.7 million pertaining to these marketing activities were netted as provided by Emerging Issues Task Force (EITF) 04-13, which we adopted as of January 1, 2005. We presented these purchase and sale activities gross in the 2004 income statement as crude oil marketing and trading revenues of $226.7 million and crude oil marketing and trading expenses of $227.2 million under the guidance provided by EITF 99-19, Reporting Revenues Gross as a Principal and/or Net as an Agent. We ceased marketing our production in this manner in March 2005 and now generally market our production at the wellhead.

Oil and Natural Gas Service Operations. Our oil and natural gas service operations consist primarily of sales of high-pressure air and the treatment and sale of lower quality crude oil (reclaimed oil). We initiated the sale of high-pressure air from our Red River units to a third party in 2004, and recorded revenues of $2.0 million

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and $3.0 million during 2004 and 2005, respectively. Higher prices for reclaimed oil sold from our central treating unit in 2005 increased oil and natural gas service operations revenues by $2.2 million to $8.8 million. Associated oil and natural gas service operations expenses increased $2.0 million from 2004 compared to 2005 due principally to an increase in the costs of purchasing and treating oil for resale.

Operating Costs and Expenses

Production Expense and Tax. Our production expense increased $9.0 million or 21%. This increase was primarily due to production expense associated with the 80 gross (45.4 net) productive wells drilled during 2005, industry inflation and higher energy costs in the Red River units. On a unit of production basis, production expense fell from $8.49 per Boe in 2004 to $7.32 per Boe in 2005.

Energy costs in the Red River units increased $3.0 million in 2004 to $9.9 million in 2005. The increased energy costs were mainly due to higher electrical costs, resulting from higher production volumes, to run compressors for the high-pressure air injection and other enhanced recovery operations in the field. Workovers in this field also increased from $0.2 million in 2004 to $1.8 million in 2005.

Production tax increased $3.7 million or 30% in 2005 compared to the 99% increase in oil and gas sales. As a percentage of oil and natural gas revenues, production tax was 4.4% in 2005 compared to 6.8% in 2004. Production taxes are based on the wellhead values of production and vary by state. Additionally, some states offer exemptions or reduced production tax rates for wells that produce less than a certain quantity of oil or gas and to encourage certain activities, such as horizontal drilling and enhanced recovery projects. In the state of Montana, a horizontal well qualifies for a 0.5% production tax rate on oil and natural gas sales for the first 18 months of production. Thereafter, the production tax rate is 9.0%. All of the wells we drilled in the Montana Bakken field qualified for the reduced production tax rate.

Our oil and natural gas revenues from the Montana Bakken field increased to approximately $93.3 million in 2005 from $19.1 million in the prior year. The addition of approximately $74.2 million in oil and gas revenues at a 0.5% production tax rate was the principal reason production tax increased 30% compared to the 99% increase in oil and gas sales.

On a unit of sales basis, production expense and production tax were as follows:

	Year ended December 31,		
	2004	**2005**	**Percent decrease**
Production expense ($/Boe)	$ 8.49	$ 7.32	(14)%
Production tax ($/Boe)	2.39	2.22	(7)%
Production expense and tax ($/Boe)	$ 10.88	$ 9.54	(12)%

Exploration Expense. Exploration expense decreased from 2004 to 2005 as a result of a reduction primarily in our dry hole expense from $9.5 million in 2004 to $1.4 million in 2005. The higher dry hole expense during 2004 was primarily attributable to dry holes in the Gulf Coast region with a higher per well cost.

Depreciation, Depletion, Amortization and Accretion. The DD&A rate per Boe decreased from $7.02 per Boe in 2004 to $6.50 per Boe in 2005. The reduction in the DD&A rate per Boe was mainly due to the addition of 32,427 MBoe of proved reserves during 2005. The amount of DD&A attributable to oil and gas properties increased by $10.6 million in 2005 due to increased production volumes. Accretion expense associated with our asset retirement obligations was $1.0 million and $1.6 million in 2004 and 2005, respectively.

Property Impairments. We evaluate our properties on a field-by-field basis, as may be necessary, when facts and circumstances such as downward reserve revisions or lower oil and natural gas prices indicate that their

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carrying amounts may not be recoverable. We recorded a $6.2 million impairment in 2004 compared to a $2.5 million impairment in 2005 on producing properties. The decrease from 2004 to 2005 was due to higher impairment charges on Gulf Coast region properties during 2004. We also evaluate our undeveloped leasehold cost and adjust the acreage valuation quarterly based on our assessment of the potential for the acreage to be developed and the market value of the acreage. Undeveloped leasehold cost is expensed over the life of the lease or transferred to the associated producing properties. Individually significant non-producing properties are periodically assessed for impairment of value and a loss is recognized if necessary. During 2004 we impaired $5.5 million of undeveloped leasehold cost compared to $4.4 million during 2005.

General and Administrative. The majority of the increase in general and administrative expense for 2005 was the result of higher wages and bonuses paid to our employees. The number of employees increased from 275 at year-end 2004 to 286 at year-end 2005, which, combined with salary adjustments and cash bonus increases, increased payroll and other employee-related expenses by $5.3 million during 2005. On a volumetric basis, our general and administrative expense, including equity compensation of $2.0 million and $13.7 million, respectively, was $2.41 per Boe and $4.34 per Boe for the years ended December 31, 2004 and 2005, respectively.

We have granted stock options and restricted stock to our employees. The terms of the grants require that, while we are a private company, we are required to purchase vested options and restricted stock at each employee s request at a per share amount derived from our shareholders equity value adjusted quarterly for our PV-10. The obligation to purchase the options is eliminated in the event we become a reporting company under Section 12 of the Exchange Act. Equity compensation expense increased from $2.0 million in 2004 to $13.7 million in 2005 primarily due to additional equity grants and a higher per share valuation resulting from the increase in our PV-10.

Interest Expense. Interest expense declined from $23.6 million in 2004 to $14.2 million in 2005. The decline in interest expense was attributable to a lower average bank indebtedness during 2005. At December 31, 2004, we had $230.0 million outstanding on our bank credit facility with an effective interest rate of 4.36% compared to $143.0 million outstanding at December 31, 2005, with an effective interest rate of 6.08%. We incurred $6.8 million and $9.3 million in interest on our credit facility in 2004 and 2005, respectively. On November 22, 2004, we signed a note with our principal shareholder for $50.0 million due March 31, 2008. The annual rate of interest was 6.00% and interest payments were due on the last day of each calendar quarter beginning December 31, 2004. We paid $308,000 and $2.9 million in interest in 2004 and 2005, respectively on this note to our principal shareholder. In December 2005, we paid the note in full to our principal shareholder. During November 2004 we utilized available borrowing capacity under our credit facility to redeem $119.5 million of our outstanding Senior Subordinated 10.25% Notes and paid a premium of $4.1 million due on the early redemption of the Notes. Total interest expense on the Senior Subordinated Notes during 2004 was $11.4 million.

Provision for Income Taxes. We recognized income tax expense of $1.1 million during the three months ended March 31, 2005 in connection with the sale of assets acquired prior to our conversion to a subchapter S-corporation from a subchapter C-corporation on May 31, 1997. These assets had Built in gains, as defined by Section 1374 of the Internal Revenue Code, which resulted in a taxable event for us.

Discontinued Operations. In July 2004, we completed the sale of all of the outstanding stock in Continental Gas Inc. (CGI) to our shareholders for $22.6 million in cash. The sales price was representative of the fair value of the net assets based on an appraisal by an independent third party who also provided us with an opinion of the fairness from a financial point of view, of the sale of CGI to the shareholders. The CGI assets included seven natural gas gathering systems and three natural gas-processing plants. These assets represented our entire natural gas gathering, marketing and processing segment and have been classified as discontinued operations for all periods presented.

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Year Ended December 31, 2003 Compared to Year Ended December 31, 2004

Revenues

Oil and Natural Gas Sales. The increase in oil and natural gas revenues from $138.9 million in 2003 to $181.4 million in 2004 was primarily attributable to higher oil and natural gas prices and reduced oil hedging losses in 2004. Oil and natural gas volumes decreased 101 MBoe from 5,255 MBoe in 2003 to 5,154 in 2004. The decrease in volumes in 2004 was mainly due to the decrease in natural gas volumes of 1,957 MMcf primarily from the Gulf Coast region. Oil and natural gas wellhead prices were $8.10 per Boe higher in 2004 compared to 2003, which offset the lower natural gas sales volumes for 2004.

The following tables present our production by product and region for the years shown:

	Year ended December 31,				
	2003		2004		Percent increase (decrease)
	Volume	Percent	Volume	Percent	
Oil (MBbl)	3,463	66%	3,688	72%	6%
Natural gas (MMcf)	10,751	34%	8,794	28%	(18)%
Total (MBoe)	5,255	100%	5,154	100%	(2)%

	Year ended December 31,				
	2003		2004		Percent increase (decrease)
	MBoe	Percent	MBoe	Percent	
Rocky Mountain	2,918	55%	3,279	64%	12%
Mid-Continent	1,659	32%	1,461	28%	(12)%
Gulf Coast	678	13%	414	8%	(39)%
Total MBoe	5,255	100%	5,154	100%	(2)%

Compared to 2003, the 2004 oil sales were higher due mainly to increased prices and slightly increased volumes. Oil production was 66% of our total produced volume for 2003, compared to 72% in 2004. The increase in oil production in 2004 was the result of response to the enhanced recovery program in the Red River units.

During 2003 and 2004, we utilized fixed-priced contracts and zero-cost collars to reduce exposure to unfavorable changes in oil and natural gas prices that are subject to significant and often volatile fluctuation. Under the fixed price contracts we received the fixed price stated in the contract. Under the zero-cost collars, if the market price of crude oil exceeded the ceiling strike price, we received the ceiling strike price and, if the market price fell below the floor strike price, we received the floor strike price. If the market price was between the floor strike price and the ceiling strike price, we received market price. Oil hedging losses of $10.1 million and $6.4 million were reported as a reduction in oil and gas revenues for the years ended December 31, 2003 and 2004, respectively.

Crude Oil Marketing and Trading. During 2003 and 2004, we purchased barrels back from certain of our wellhead purchasers downstream of the initial sales point to exchange at the Cushing, Oklahoma hub in order to minimize pricing differentials with the NYMEX oil futures contract. We presented these purchase and sale activities gross in the 2003 and 2004 income statements as crude oil marketing and trading revenues of $169.5 million, including a trading gain of approximately $1.5 million associated with derivatives, and $226.7 million, respectively, and crude oil marketing and trading expenses of $166.7 million and $227.2 million, respectively, under the guidance provided by EITF 99-19, Reporting Revenues Gross as a Principal and/or Net as an Agent. Crude oil marketing and trading amounts increased between 2003 and 2004 due to higher volumes and commodity prices.

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Oil and Natural Gas Service Operations. We initiated the sale of high-pressure air to a third party in 2004, which increased our oil and natural gas service operations revenues $2.0 million from 2003 to 2004.

Oil and natural gas service operations expense increased from 2003 to 2004 due to an additional 30 MBbls of oil treated at our central treating unit along with higher oil prices, which increased the costs of purchasing and treating oil for resale.

Operating Costs and Expenses

Production Expense and Tax. Production expense increased from $40.8 million in 2003 to $43.8 million in 2004. The $3.0 million increase was principally the result of increased energy costs in the Red River units of $3.8 million partially offset by a decrease in contract labor and outside operated well expense of $1.4 million. The commencement, during 2003, of High Pressure Air Injection (HPAI) in the Red River units contributed to the increase in energy costs.

Our production tax increased from 2003 compared to 2004 due to the increase in oil and natural gas prices and increased oil volumes in 2004. Production taxes are based on the wellhead values of production and vary across different regions. On a unit of sales basis, production expense and production tax were as follows:

	Year ended December 31,		
	2003	**2004**	**Percent increase**
Production expense ($/Boe)	$ 7.77	$ 8.49	9%
Production tax ($/Boe)	1.95	2.39	23%
Production expense and tax ($/Boe)	$ 9.72	$ 10.88	12%

Exploration Expense. Exploration expenses decreased by $4.6 million from $17.2 million in 2003 to $12.6 million in 2004. This decrease was attributable to lower dry hole expense and seismic costs in 2004.

Depreciation, Depletion, Amortization and Accretion. Depreciation, depletion and amortization (DD&A) of oil and gas properties decreased by $1.1 million to $36.2 million during 2004 as a result of lower production and a lower rate per Boe. The DD&A rate per Boe decreased from $7.10 per Boe in 2003 to $7.02 per Boe in 2004. Accretion expense associated with our asset retirement obligations was $1.2 million and $1.0 million in 2003 and 2004, respectively. Depreciation of other assets decreased by $0.3 million to $1.4 million in 2004.

Property Impairments. We evaluate, as may be necessary due to downward reserve revisions or lower oil and natural gas prices, our properties for impairment. We recorded a $3.8 million impairment in 2003 and a $6.2 million impairment primarily associated with our Gulf Coast properties in 2004.

We also evaluate our undeveloped leasehold cost and adjust the acreage valuation quarterly based on our assessment of the potential for the acreage to be developed and the market value of the acreage. Undeveloped leasehold cost is expensed over the life of the lease or transferred to the associated producing properties. Individually significant non-producing properties are periodically assessed for impairment of value and a loss is recognized if necessary. During 2003 we impaired $5.2 million of undeveloped leasehold cost compared to $5.5 million during 2004.

General and Administrative. The majority of the increase in general and administrative expense of $2.8 million to $12.4 million was the result of higher wages and other employee-related expenses of $2.4 million. Our general and administrative expense, including equity compensation of $0.2 million and $2.0 million, respectively, was $1.83 per Boe and $2.41 per Boe for the years ended December 31, 2003 and 2004, respectively.

During 2003 and 2004 we granted stock options to our employees. As permitted by SFAS No. 123, we have elected to follow the intrinsic value method promulgated under APB Opinion 25. The terms of the grants require

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that, while we are a private company, we are required to purchase vested options at each employee s request at a per share amount derived from our shareholders equity value adjusted quarterly for our PV-10. The obligation to purchase the options is eliminated in the event we become a reporting company under Section 12 of the Exchange Act. Equity compensation expense increased from 2003 compared to 2004 as a result of an increase in the formula-derived value of our shares due to higher shareholders equity and greater PV-10.

Interest Expense. The increase in interest expense from 2003 compared to 2004 was the result of higher average interest rates. At December 31, 2003 and 2004, our long term debt, including the current portion and capital leases, was $290.9 million and $290.5 million, respectively. At December 31, 2003, we had $132.9 million outstanding debt on our bank credit facility with an effective interest rate of 3.75% compared to $230.0 million outstanding debt at December 31, 2004, with an effective interest rate of 4.36%. We incurred $4.9 million and $6.8 million in interest on our bank credit facility in 2003 and 2004, respectively. On November 22, 2004, we signed a note with our principal shareholder for $50.0 million due March 31, 2008. The annual rate of interest was 6.00% and interest payments were due the last day of each calendar quarter beginning December 31, 2004. We paid $308,000 in interest to our principal shareholder in 2004. We redeemed $119.5 million of our outstanding Senior Subordinated 10.25% Notes during November 2004 and paid a premium of $4.1 million due on the early redemption of these notes. Total interest expense on these notes was $13.0 million and $11.4 million during 2003 and 2004, respectively.

Discontinued Operations. In July 2004, we completed the sale of all of the outstanding stock in CGI to our shareholders for $22.6 million in cash. The sales price was representative of the fair value of the net assets based on an appraisal by an independent third party who also provided us with an opinion of the fairness from a financial point of view, of the sale of CGI to the shareholders. The CGI assets included seven natural gas gathering systems and three natural gas-processing plants. These assets represented our entire natural gas gathering, marketing and processing segment and have been classified as discontinued operations for all periods presented.

Liquidity and Capital Resources

Our primary sources of liquidity have been cash flows generated from operating activities and financing provided by our bank credit facility and principal shareholder. In January 2005, our principal shareholder contributed $2.0 million of the previously loaned amount to us. We paid the $48.0 million outstanding balance due on our note with our principal shareholder in December 2005. We believe that funds from operating cash flows and the bank credit facility should be sufficient to meet our cash requirements inclusive of, but not limited to, normal operating needs, debt service obligations, planned capital expenditures, and commitments and contingencies for the next 12 months. We intend to fund our longer term cash requirements beyond 12 months through operating cash flows, commercial bank borrowings and access to equity and debt capital markets. Although our longer term needs may be impacted by factors discussed in the section entitled Risk Factors, such as declines in oil and natural gas prices, drilling results, ability to obtain needed capital on satisfactory terms, and other risks which could negatively impact production and our results of operations, we currently anticipate that we will be able to generate or obtain funds sufficient to meet our long-term cash requirements. On April 13 and August 15, 2006, we paid cash dividends of approximately $60.0 million and $27.6 million, respectively, to our existing shareholders and, subject to forfeiture, to holders of unvested restricted stock. At December 31, 2005 and September 30, 2006, we had cash and cash equivalents of $6.0 million and $4.5 million, respectively, and available borrowing capacity on our credit facility of $107.0 million and $140.0 million, respectively.

Cash Flow from Operating Activities

Our net cash provided by operating activities was $65.2 million, $93.9 million and $265.3 million for the years ended December 31, 2003, 2004 and 2005 and $162.0 million and $289.0 million for the nine months

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ended September 30, 2005 and 2006, respectively. The increases in operating cash flows in 2005 and 2006 were principally due to increased production and higher oil and natural gas prices. Additionally, hedging losses were $10.1 million and $6.4 million in 2003 and 2004, respectively. There were no hedges in place during 2005 or during the nine months ended September 30, 2006.

Cash Flow from Investing Activities

During the years ended December 31, 2003, 2004 and 2005, we invested $114.1 million, $94.3 million, and $144.8 million, respectively, and during the nine months ended September 30, 2005 and 2006, we invested $94.2 million and $221.3 million, respectively, in our capital program, inclusive of dry hole and seismic costs. The increases in our capital program in 2005 and 2006 were due to the implementation of enhanced recovery in our Red River units and additional exploration and development drilling.

Cash Flow from Financing Activities

Net cash provided by (used in) financing activities was $43.3 million for 2003, ($7.2) million for 2004, and ($141.5) million for 2005 and ($85.7) million and ($71.2) million for the nine months ended September 30, 2005 and 2006, respectively. In 2004, cash used in financing activities was primarily attributable to the repurchase of our Senior Subordinated Notes. In 2005, cash used in financing activities was primarily attributable to the repayment of long-term debt. During the nine months ended September 30, 2005, cash used in financing activities was primarily attributable to the payment of long-term debt. During the nine months ended September 30, 2006, cash used in financing activities was primarily attributable to the payment of cash dividends. Our long-term debt, including the current portion and capital leases, was $290.9 million, $290.5 million and $143.0 million at December 31, 2003, 2004 and 2005, respectively, and $160.0 million at September 30, 2006.

Credit Facility

We had $143.0 million outstanding under our bank credit facility at December 31, 2005 and $174.0 million outstanding under our bank credit facility at November 14, 2006. The credit facility was amended on April 12, 2006. The amended facility matures on April 12, 2011, and borrowings under our credit facility bear interest, payable quarterly, at (a) a rate per annum equal to the London Interbank Offered Rate for one, two, three or six months as offered by the lead bank plus an applicable margin ranging from 100 to 175 basis points or (b) the lead bank s reference rate. The amended credit facility has a note amount of $750 million, a borrowing base of $500 million, subject to semi-annual redetermination, and a commitment level of $300 million. The terms of the amended facility allow us to determine the commitment level at any level up to the borrowing base.

The amended credit facility contains restrictive covenants that may limit our ability to, among other things, incur additional indebtedness, sell assets, make loans to others, make investments, enter into mergers, change material contracts, incur liens and engage in certain other transactions without the prior consent of the lenders. The facility also requires us to maintain certain ratios as defined and further described in our credit facility: a Current Ratio of not less than 1.0 to 1.0, a Total Funded Debt to EBITDAX of no greater than 3.75 to 1.0. These covenants were also included in our previous credit facility. As of December 31, 2005 and September 30, 2006, we were in compliance with all covenants.

Future Capital Expenditures and Commitments

We evaluate opportunities to purchase or sell oil and natural gas properties in the marketplace and could participate as a buyer or seller of properties at various times. We seek acquisitions that utilize our technical expertise or offer opportunities to expand our existing core areas.

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Expenditures for exploration and development of oil and natural gas properties are the primary use of our capital resources. We anticipate investing approximately $302 million for capital and exploration expenditures in 2006 as follows (in millions):

	Amount
Exploration and development drilling	$ 237
Capital facilities	27
Workover / recompletion	16
Land costs	16
Seismic	5
Vehicles, computers & other equipment	1
	$ 302

Our budgeted capital expenditures are expected to increase approximately 109% over the $145 million invested during 2005. We plan to invest approximately $150 million in development drilling. In the Red River units, we plan to invest approximately $67 million to drill infill wells and extend horizontal laterals on existing wells to increase production and sweep efficiency of the enhanced recovery projects. Most of the remaining development drilling budget is expected to be invested in the drilling of development wells in the Montana Bakken field. We have budgeted approximately $87 million for exploratory drilling with approximately $28 million allocated to drilling exploratory wells in the North Dakota Bakken field.

On November 7, 2006, our Board of Directors approved a capital expenditure budget of $400 million for calendar year 2007 allocated as follows:

	Wells planned for drilling	Capital expenditures (in millions)
Rocky Mountain:		
Red River units	41	$ 123
Bakken field	65	113
Other	24	31
Mid-Continent	54	62
Gulf Coast	3	4
Total exploration and development drilling	187	$ 333
Capital facilities		28
Workover / recompletion		9
Land costs		19
Seismic		7
Vehicles, computers & other equipment		4
Total		$ 400

Although we cannot provide any assurance, assuming successful implementation of our strategy, including the future development of our proved reserves and realization of our cash flows as anticipated, we believe that our remaining cash balance and cash flows from operations will be sufficient to satisfy our 2006 and 2007 capital budgets. The actual amount and timing of our capital expenditures may differ materially from our estimates as a result of, among other things, actual drilling results, the availability of drilling rigs and other services and equipment, and regulatory, technological and competitive developments.

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Shareholder Distribution

In 2004, we made a distribution of $14.9 million to our shareholders and in 2005 we made a $2.0 million distribution to our shareholders. On April 13 and August 15, 2006, we paid cash dividends of approximately $60.0 million and $27.6 million, respectively, to our shareholders and, subject to forfeiture, to holders of unvested restricted stock. In connection with the completion of this offering, we will convert from a subchapter S-corporation to a subchapter C-corporation, and we do not anticipate paying any additional cash dividends on our common stock in the foreseeable future.

Expenses to be Recognized Following Completion of the Offering

We expect to recognize a charge to earnings estimated to be approximately $152.9 million as of September 30, 2006 to record deferred taxes as a result of our conversion to a C-corporation upon completion of this offering. This charge represents taxes provided on the difference between the book and tax basis of our assets. In addition, we expect to recognize a charge to earnings of approximately $ million representing compensation expense associated with our equity compensation plan upon completion of this offering, assuming an offering price at the midpoint of the range set forth on the cover page of the prospectus.

The terms of our restricted stock grants and stock option grants stipulate that while we are a private company, we are required to purchase the vested restricted stock and stock acquired from stock option exercises at each employee s request based upon the purchase price as determined by a formula specified in each award agreement. Additionally, we have the right to purchase vested restricted stock and stock acquired from stock option exercises at the same price upon termination of employment for any reason and for a period of two years subsequent to employment. We have historically measured compensation cost for the awards based upon the formula purchase price which is determined by calculating a per share value for shareholders equity adjusted for the excess of each period s ending PV-10 oil and gas reserve valuation over the book value of oil and gas properties.

The right to sell and requirement to purchase our restricted stock grants will lapse when we become a reporting company under Section 12 of the Exchange Act. Upon becoming a reporting company under Section 12 of the Exchange Act, we will record the charge to earnings described above to adjust the plan determined share price to the price received in this offering and account for the grants under the fair value provisions of SFAS 123(R) thereafter.

Hedging

We account for derivative instruments in accordance with SFAS No. 133 Accounting for Derivative Instruments and Hedging Activities. The specific accounting treatment for changes in the market value of the derivative instruments used in hedging activities is determined based on the designation of the derivative instruments as a cash flow or fair value hedge and effectiveness of the derivative instruments.

We have utilized fixed-price contracts and zero-cost collars to reduce exposure to unfavorable changes in oil and natural gas prices that are subject to significant and often volatile fluctuation. Under the fixed price physical delivery contracts we received the fixed price stated in the contract. Under the zero-cost collars, if the market price of crude oil was less than the ceiling strike price and greater than the floor strike price, we received market price. If the market price of crude oil exceeded the ceiling strike price or fell below the floor strike price, we received the applicable collar strike price.

We did not hedge any of our oil or natural gas production during 2005 and have not entered into any such hedges from January 1, 2006 through the date of this filing. We do not currently have plans to hedge any of our 2006 production. We recognized hedging losses of $10.1 million and $6.4 million during 2003 and 2004, respectively.

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Obligations and Commitments

We have the following contractual obligations and commitments as of December 31, 2005:

	Payments due by period				
	Total	Less than 1 year	1 - 3 years	3 - 5 years	More than 5 years
			(in thousands)		
Bank credit facility(1)	$ 143,000	$	$ 143,000	$	$
Operating lease obligations(2)	15,944	5,239	10,683	22	
Asset retirement obligations(3)	34,353	2,120	2,798	494	28,941
Total contractual cash obligations	$ 193,297	$ 7,359	$ 156,481	$ 516	$ 28,941

(1) Payments on the bank credit facility listed in the table exclude interest.

(2) Operating leases consist of compressors utilized in field operations, vehicles and office equipment.

(3) Amounts represent expected asset retirements by period.

Critical Accounting Policies and Practices

Our historical consolidated financial statements and notes to our historical consolidated financial statements contain information that is pertinent to our management s discussion and analysis of financial condition and results of operations. Preparation of financial statements in conformity with accounting principles generally accepted in the United States requires that our management make estimates, judgments and assumptions that affect the reported amounts of assets, liabilities, revenues and expenses, and the disclosure of contingent assets and liabilities. However, the accounting principles used by us generally do not change our reported cash flows or liquidity. Interpretation of the existing rules must be done and judgments made on how the specifics of a given rule apply to us.

In management s opinion, the more significant reporting areas impacted by management s judgments and estimates are revenue recognition, the choice of accounting method for oil and natural gas activities, oil and natural gas reserve estimation, asset retirement obligations and impairment of assets. Management s judgments and estimates in these areas are based on information available from both internal and external sources, including engineers, geologists and historical experience in similar matters. Actual results could differ from the estimates, as additional information becomes known.

Revenue Recognition

We derive substantially all of our revenues from the sale of oil and natural gas. Oil and gas revenues are recorded in the month the product is delivered to the purchaser and title transfers. We generally receive payment from one to three months after the sale has occurred. Each month we estimate the volumes sold and the price at which they were sold to record revenue. Variances between estimated revenue and actual amounts are recorded in the month payment is received.

Successful Efforts Method of Accounting

We utilize the successful efforts method of accounting for our oil and natural gas exploration and development activities. Exploration expenses, including geological and geophysical costs, rentals and exploratory dry holes, are charged against income as incurred. Costs of successful wells and related production equipment and developmental dry holes are capitalized and amortized on an individual property, field or unit basis using the unit-of-production method as oil and natural gas is produced. This accounting method may yield significantly different results than the full cost method of accounting.

Depreciation, depletion and amortization, or DD&A, of capitalized drilling and development costs of oil and natural gas properties are generally computed using the unit of production method on an individual property,

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field or unit basis based on total estimated proved developed oil and natural gas reserves. Amortization of producing leasehold is based on the unit-of-production method using total estimated proved reserves. In arriving at rates under the unit-of-production method, the quantities of recoverable oil and natural gas are established based on estimates made by our geologists and engineers and independent engineers. Service properties, equipment and other assets are depreciated using the straight-line method over estimated useful lives of 5 to 40 years. Upon sale or retirement of depreciable or depletable property, the cost and related accumulated DD&A are eliminated from the accounts and the resulting gain or loss is recognized.

Non-producing properties consist of undeveloped leasehold costs and costs associated with the purchase of certain proved undeveloped reserves. Undeveloped leasehold cost is expensed over the life of the lease or transferred to the associated producing properties. Individually significant non-producing properties are periodically assessed for impairment of value.

Oil and Natural Gas Reserves and Standardized Measure of Future Cash Flows

Our independent engineers and technical staff prepare the estimates of our oil and natural gas reserves and associated future net cash flows. Current accounting guidance allows only proved oil and natural gas reserves to be included in our financial statement disclosures. The SEC has defined proved reserves as the estimated quantities of crude 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. Even though our independent engineers and technical staff are knowledgeable and follow authoritative guidelines for estimating reserves, they must make a number of subjective assumptions based on professional judgments in developing the reserve estimates. Reserve estimates are updated at least annually and consider recent production levels and other technical information about each field. Periodic revisions to the estimated reserves and future cash flows may be necessary as a result of a number of factors, including reservoir performance, new drilling, oil and natural gas prices, cost changes, technological advances, new geological or geophysical data, or other economic factors. We cannot predict the amounts or timing of future reserve revisions. If such revisions are significant, they could significantly alter future DD&A and result in impairment of assets that may be material.

Asset Retirement Obligations

In June 2001, the FASB issued SFAS No. 143, which applies to legal obligations associated with the retirement of long-lived assets that result from the acquisition, construction, development and the normal operation of a long-lived asset. The primary impact of this standard on us relates to oil and natural gas wells on which we have a legal obligation to plug and abandon. SFAS No. 143 requires us to record the fair value of a liability for an asset retirement obligation in the period in which it is incurred and a corresponding increase in the carrying amount of the related long-lived asset. The determination of the fair value of the liability requires us to make numerous judgments and estimates, including judgments and estimates related to the future salvage value of well equipment, future costs to plug and abandon wells, future inflation rates and estimated lives of the related assets.

Impairment of Assets

All of our long-lived assets are monitored for potential impairment when circumstances indicate that the carrying value of an asset may be greater than its future net cash flows, including cash flows from risk adjusted proved reserves. The evaluations involve a significant amount of judgment since the results are based on estimated future events, such as future sales prices for oil and natural gas, future costs to produce these products, estimates of future oil and natural gas reserves to be recovered and the timing thereof, the economic and regulatory climates and other factors. The need to test a field for impairment may result from significant declines in sales prices or downward revisions to oil and natural gas reserves. Any assets held for sale are reviewed for

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impairment when we approve the plan to sell. Estimates of anticipated sales prices are highly judgmental and subject to material revision in future periods. Because of the uncertainty inherent in these factors, we cannot predict when or if future impairment charges will be recorded.

Off-Balance Sheet Arrangements

Currently, we do not have any off-balance sheet arrangements.

Recent Accounting Pronouncements

On December 16, 2004, the Financial Accounting Standards Board (FASB) issued SFAS No. 123(R), Share-Based Payment , which is a revision of SFAS No. 123, Accounting for Stock-Based Compensation. SFAS No. 123(R) supersedes APB 25 and amends SFAS No. 95, Statement of Cash Flows. Generally, the approach in SFAS No. 123(R) is similar to the approach described in SFAS No. 123. However, SFAS No. 123(R) requires all share-based payments to employees, including grants of employee stock options, be recognized in the consolidated financial statements based on their estimated fair values. Pro forma disclosures are no longer an alternative.

We have adopted SFAS 123(R) effective January 1, 2006. So long as we are not a reporting company under Section 12 of the Exchange Act, we have an obligation, and accrue a liability for the amount required, to purchase shares acquired through the exercise of stock options and vested restricted shares at a formula price set forth in the award agreements. As a result of this offering, we will no longer have this purchase obligation, and our equity compensation expense will be based on the valuation methodologies contained in SFAS 123(R).

On June 1, 2005, the FASB issued SFAS Statement No. 154, Accounting Changes and Error Corrections (SFAS No. 154), which will require entities that voluntarily make a change in accounting principle to apply that change retrospectively to prior periods financial statements, unless this would be impracticable. SFAS No. 154 supersedes Accounting Principles Board Opinion No. 20, Accounting Changes (APB 20), which previously required that most voluntary changes in accounting principle be recognized by including in the current period s net income the cumulative effect of changing to the new accounting principle. SFAS No. 154 also makes a distinction between retrospective application of an accounting principle and the restatement of financial statements to reflect the correction of an error.

Another significant change in practice under SFAS No. 154 will be that if an entity changes its method of depreciation, amortization, or depletion for long-lived, non-financial assets, the change must be accounted for as a change in accounting estimate. Under APB 20, such a change would have been reported as a change in accounting principle. SFAS No. 154 applies to accounting changes and error corrections that are made in fiscal years beginning after December 15, 2005. Management has not completed its assessment of the impact of SFAS No. 154, but does not anticipate any material impact from implementation of this accounting standard.

In April 2005, the FASB issued Staff Position No. FAS 19-1, Accounting for Suspended Well Costs , or FSP. The FSP amended paragraphs 31-34 of SFAS No. 19, to allow continued capitalization of exploratory well costs beyond one year from the completion of drilling under circumstances where the well has found a sufficient quantity of reserves to justify its completion as a producing well and the enterprise is making sufficient progress assessing the reserves and the economic and operating viability of the project. The guidance in the FSP was effective for the first reporting period beginning after April 4, 2005. We adopted the new requirements accordingly and do not have any capitalized exploratory well costs beyond one year from the completion of drilling.

In September 2006, the Securities and Exchange Commission issued Staff Accounting Bulletin (SAB) No. 108, *Considering the Effects of Prior Year Misstatements when Quantifying Current Year Misstatements*.

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SAB No. 108 requires analysis of misstatements using both an income statement (rollover) approach and a balance sheet (iron curtain) approach in assessing materiality and provides for a one-time cumulative effect transition adjustment. We have applied the guidance of SAB No. 108 for all periods presented.

In June 2006, the FASB issued Interpretation No. 48, *Accounting for Uncertainty in Income Taxes* (FIN 48). The interpretation clarifies the accounting for uncertainty in income taxes recognized in a company s financial statements in accordance with Statement of Financial Accounting Standards No. 109, *Accounting for Income Taxes*. The interpretation is effective for fiscal years beginning after December 15, 2006. The adoption of FIN 48 is not expected to have a material impact on our consolidated financial position or results of operations.

In September 2006, the FASB finalized SFAS No. 157, *Fair Value Measurements* which will become effective in 2008. This Statement defines fair value, establishes a framework for measuring fair value, and expands disclosures about fair value measurements; however, it does not require any new fair value measurements. The provisions of SFAS No. 157 will be applied prospectively to fair value measurements and disclosures in our Consolidated Financial Statements beginning in the first quarter of 2008. The adoption of SFAS No. 157 is not expected to have a material impact on our consolidated financial position or results of operations.

Inflation

Historically, general inflationary trends have not had a material effect on our operating results. However, we have experienced inflationary pressure on technical staff compensation and the cost of oilfield services and equipment due to the increase in drilling activity and competitive pressures resulting from higher oil and natural gas prices in recent years.

Quantitative and Qualitative Disclosures About Market Risk

We are exposed to a variety of market risks including credit risk, commodity price risk and interest rate risk. We address these risks through a program of risk management including the use of derivative instruments.

Credit Risk. We monitor our risk of loss due to non-performance by counterparties of their contractual obligations. Our principal exposure to credit risk is through the sale of our oil and natural gas production, which we market to energy marketing companies, refineries and affiliates, as described under Certain relationships and related party transactions. We monitor our exposure to these counterparties primarily by reviewing credit ratings, financial statements and payment history. We extend credit terms based on our evaluation of each counterparty s credit worthiness. Although we have not generally required our counterparties to provide collateral to support trade receivables owed to us, we routinely require prepayment of working interest holders proportionate share of drilling costs. For such prepayments, a liability is recorded and subsequently reduced as the associated work is performed. In this manner, we reduce credit risk.

Commodity Price Risk. We are exposed to market risk as the prices of crude oil and natural gas are subject to fluctuations resulting from changes in supply and demand. To partially reduce price risk caused by these market fluctuations, we have hedged in the past, and may hedge in the future, through the utilization of derivatives, including zero-cost collars and fixed price contracts, a portion of our production. We had no hedging contracts in place at December 31, 2004 or during 2005 and do not currently plan to hedge any of our 2006 production.

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Interest Rate Risk. Our exposure to changes in interest rates relates primarily to long-term debt obligations. We manage our interest rate exposure by limiting our variable-rate debt to a certain percentage of total capitalization and by monitoring the effects of market changes in interest rates. We may utilize interest rate derivatives to alter interest rate exposure in an attempt to reduce interest rate expense related to existing debt issues. Interest rate derivatives are used solely to modify interest rate exposure and not to modify the overall leverage of the debt portfolio. We are exposed to changes in interest rates as a result of our credit facility. We had total indebtedness of $174.0 million outstanding under our credit facility at November 14, 2006. The impact of a 1% increase in interest rates on this amount of debt would result in increased interest expense of approximately $1.7 million and a corresponding decrease in net income. The fair value of long-term debt is estimated based on quoted market prices and management s estimate of current rates available for similar issues. The following table itemizes our long-term debt maturities and the weighted-average interest rates by maturity date:

	2006	2007	2008	2009	2010	2011	Total
				(in thousands)			
Variable rate debt:							
Credit facility:							
Principal amount	$	$	$	$	$	$ 174,000	$ 174,000
Weighted-average interest rate						6.75%	6.75%

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Business and Properties

Our Business

We are an independent oil and natural gas exploration and production company with operations in the Rocky Mountain, Mid-Continent and Gulf Coast regions of the United States. We focus our exploration activities in large new or developing plays that provide us the opportunity to acquire undeveloped acreage positions for future drilling operations. We have been successful in targeting large repeatable resource plays where horizontal drilling, advanced fracture stimulation and enhanced recovery technologies provide the means to economically develop and produce oil and natural gas reserves from unconventional formations. As a result of these efforts, we have grown substantially through the drillbit, adding 86.2 MMBoe of proved oil and natural gas reserves through extensions and discoveries from January 1, 2001 through December 31, 2005 compared to 4.7 MMBoe added through proved reserve purchases during that same period.

As of December 31, 2005, our estimated proved reserves were 116.7 MMBoe, with estimated proved developed reserves of 80.3 MMBoe, or 69% of our total estimated proved reserves. Crude oil comprised 85% of our total estimated proved reserves. At December 31, 2005, we had 1,233 scheduled drilling locations on the 1,523,000 gross (961,000 net) acres that we held. For the year ended December 31, 2005 and the nine months ended September 30, 2006, we generated revenues of $375.8 million and $369.7 million, respectively, and operating cash flows of $265.3 million and $289.0 million, respectively.

The following table summarizes our total estimated proved reserves, PV-10 and net producing wells as of December 31, 2005, average daily production for the three months ended September 30, 2006 and the reserve-to-production ratio in our principal regions. Our reserve estimates as of December 31, 2005 are based primarily on a reserve report prepared by Ryder Scott Company, L.P., our independent reserve engineers. In preparing its report, Ryder Scott Company, L.P. evaluated properties representing approximately 83% of our PV-10. Our technical staff evaluated properties representing the remaining 17% of our PV-10.

	At December 31, 2005				Average daily production		
	Proved reserves (MBoe)	Percent of total	PV-10(1) (in millions)	Net producing wells	Third quarter 2006 (Boe per day)	Percent of total	Annualized reserve/ production index(2)
Rocky Mountain:							
Red River units	67,711	58%	$ 1,215	187	11,162	44%	16.6
Bakken field	24,041	21%	505	34	7,800	30%	8.4
Other	9,065	8%	137	230	1,620	6%	15.3
Mid-Continent	15,472	13%	328	630	4,236	17%	10.0
Gulf Coast	376		19	23	812	3%	1.3
Total	116,665	100%	$ 2,204	1,104	25,630	100%	12.5

(1) PV-10 is a non GAAP financial measure and generally differs from Standardized Measure, the most directly comparable GAAP financial measure, because it does not include the effects of income taxes on future net revenues. However, our PV-10 and our Standardized Measure are equivalent because we are a subchapter S-corporation. In connection with the closing of this offering, we will convert to a subchapter C-corporation. Our pro-forma Standardized Measure, assuming our conversion to a subchapter C-corporation, was $1.4 billion at December 31, 2005. Neither PV-10 nor Standardized Measure represents an estimate of the fair market value of our oil and gas properties. We and others in the industry use PV-10 as a measure to compare the relative size and value of proved reserves held by companies without regard to the specific tax characteristics of such entities.

(2) The Annualized Reserve/Production Index is the number of years proved reserves would last assuming current production continued at the same rate. This index is calculated by dividing annualized third quarter 2006 production into the proved reserve quantity at December 31, 2005.

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The following table provides additional information regarding our key development areas:

	At December 31, 2005					2006 Budget	
	Developed acres		Undeveloped acres		Scheduled drilling locations(1)	Wells planned for drilling	Capital expenditures (in millions)
	Gross	Net	Gross	Net			
Rocky Mountain:							
Red River units	144,176	128,047			135	23	$ 84
Bakken field	52,421	38,971	588,081	356,426	918	51	107
Other	45,720	36,153	358,649	208,612	71	11	39
Mid-Continent	152,734	99,279	115,746	73,582	96	83	62
Gulf Coast	41,842	11,890	23,598	7,873	13	9	9
Total	436,893	314,340	1,086,074	646,493	1,233	177	$ 301

(1) Scheduled drilling locations represent total gross locations specifically identified and scheduled by management as an estimate of our future multi-year drilling activities on existing acreage. Of the total locations shown in the table, 265 are classified as PUDs. As of September 30, 2006, we have commenced drilling 146 locations shown in the table, including 54 PUD locations. Scheduled drilling locations include 37 potential drilling sites in our New Albany Shale, Lewis Shale, Floyd Shale and Woodford Shale projects. While we owned 168,000 gross (72,000 net) undeveloped acres in these projects as of December 31, 2005, we have not sufficiently evaluated the opportunities on our acreage at this date to schedule further locations. Our actual drilling activities may change depending on oil and natural gas prices, the availability of capital, costs, drilling results, regulatory approvals and other factors. See Risk Factors Risks Relating to the Oil and Natural Gas Industry and Our Business.

Our Business Strategy

Our goal is to increase shareholder value by finding and developing crude oil and natural gas reserves at costs that provide an attractive rate of return on our investment. The principal elements of our business strategy are:

Growth Through Low-Cost Drilling. Substantially all of our annual capital expenditures are invested in drilling projects and acreage and seismic acquisitions. From January 1, 2001 through December 31, 2005, proved oil and natural gas reserve additions through extensions and discoveries were 86.2 MMBoe compared to 4.7 MMBoe of proved reserve purchases.

Internally Generate Prospects. Our technical staff has internally generated substantially all of the opportunities for the investment of our capital. Because we have been an early entrant in new or emerging plays, our costs to acquire undeveloped acreage have generally been less than those of later entrants into a developing play. As an example of the cost advantage of entering a play early, our per acre costs for our lease acquisitions in the North Dakota Bakken field during 2003 and 2004 were approximately 80% lower than the per acre costs paid by third parties and by us in the federal and state lease auctions for acreage near our holdings in that area during 2005.

Focus on Unconventional Oil and Natural Gas Resource Plays. Our experience with horizontal drilling, advanced fracture stimulation and enhanced recovery technologies allows us to commercially develop unconventional oil and natural gas resource plays, such as the Red River B dolomite, Bakken Shale and Woodford Shale formations. Production rates in the Red River units also have been increased through the use of enhanced recovery technology. Our production from the Red River units and the Bakken field comprised approximately 74% of our total oil and natural gas production during the three months ended September 30, 2006.

Acquire Significant Acreage Positions in New or Developing Plays. In addition to the 395,000 net acres held in the Montana and North Dakota Bakken field, we held 145,000 net acres in other oil and natural gas shale plays as of December 31, 2005. Our technical staff is focused on identifying and testing new unconventional oil and natural gas resource plays where significant reserves could be developed if commercial production rates can be achieved through advanced drilling, fracture stimulation and enhanced recovery techniques.

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Our Business Strengths

We have a number of strengths that we believe will help us successfully execute our strategies:

Large Drilling and Acreage Inventory. Within the Bakken field, we owned approximately 356,000 net undeveloped acres and had identified over 900 drilling locations as of December 31, 2005. We plan to allocate almost one-third of our current year capital expenditure budget towards developing our Bakken acreage position. Our large number of identified drilling locations provide for a multi-year drilling inventory.

Within other unconventional plays such as the Lewis Shale in Wyoming, the Woodford Shale in Oklahoma, the New Albany Shale in Kentucky and Indiana and the Floyd Shale in Mississippi, we owned approximately 72,000 net undeveloped acres as of December 31, 2005. Within another resource play, the Pierre Shale in North Dakota and Montana, we have 56,000 net acres held by deeper production.

Additionally, at December 31, 2005, we owned approximately 218,000 net undeveloped acres in other projects, including 36,000 net undeveloped acres in Roosevelt County, Montana on which we are planning a 38-square mile 3-D seismic shoot in 2006, 31,000 net undeveloped acres in the Big Horn Basin in Wyoming on which we plan to drill four wells in 2006, 29,000 net undeveloped acres in Bowman County, North Dakota on which we plan to drill a horizontal Red River B well in 2006 and 12,000 net undeveloped acres in Saskatchewan, Canada on which we plan to drill a horizontal Red River C well in 2006.

Within the Red River units, we plan to drill 131 horizontal wells and 51 horizontal extensions of existing wellbores over the next two to three years in order to increase the density of both producing and injection wellbores. We believe these operations will increase production and sweep efficiency. Production in the Red River units, as projected by our proved reserve report for the year ended December 31, 2005, is expected to peak in 2009 at approximately 19,000 net Boe per day. During the three months ended September 30, 2006, production in the Red River units averaged approximately 11,162 net Boe per day.

Horizontal Drilling and Enhanced Recovery Experience. In 1992, we drilled our initial horizontal well, and we have drilled over 300 horizontal wells since that time, which represented more than one-half of our total wells drilled during that period. We also have substantial experience with enhanced recovery methods and currently serve as the operator of 48 waterflood units. Additionally, we operate eight high pressure air injection floods in the United States.

Control Operations Over a Substantial Portion of Our Assets and Investments. As of December 31, 2005, we operated properties comprising 97% of our PV-10. By controlling operations, we are able to more effectively manage the cost and timing of exploration and development of our properties, including the drilling and fracture stimulation methods used.

Experienced Management Team. Our senior management team has extensive expertise in the oil and gas industry. Our Chief Executive Officer, Harold G. Hamm, began his career in the oil and gas industry in 1967. Our seven senior officers have an average of 25 years of oil and gas industry experience. Additionally, our technical staff, which includes 20 petroleum engineers, 13 geoscientists and seven landmen, has an average of more than 19 years experience in the industry.

Strong Financial Position. As of November 14, 2006, we had outstanding borrowings under our credit facility of approximately $174.0 million. We believe that our planned exploration and development activities will be funded substantially from our operating cash flows. As a result of our limited borrowings under our credit facility and strong operational cash flows, we did not enter into any oil or natural gas price hedges for our 2005 production, and we do not currently have plans to hedge any of our 2006 production.

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Conversion to Subchapter C-Corporation

We are currently a subchapter S-corporation under the rules and regulations of the Internal Revenue Service. However, upon the consummation of this offering, we will have more shareholders than the IRS rules and regulations governing S-corporations allow, and therefore, we will convert automatically from a subchapter S-corporation to a subchapter C-corporation. In connection with this conversion, we will record a charge to earnings estimated to be approximately $152.9 million as of September 30, 2006 to recognize deferred taxes.

Proved Reserves

The following table sets forth our estimated proved oil and natural gas reserves, the PV-10 and standardized measure of discounted future net cash flows as of December 31, 2005 by reserve category. Ryder Scott Company, L.P., our independent petroleum engineers, evaluated properties representing approximately 83% of our PV-10, and our technical staff evaluated the remaining properties. Oil and natural gas prices in effect at December 31, 2005, $61.04 per Bbl and $11.23 per MMBtu adjusted for location and quality by field, were used in the computation of future net cash flows.

	Oil (MBbls)	Gas (MMcf)	Total (MBoe)	PV-10(1) (in millions)
Proved developed producing	68,019	54,168	77,047	$ 1,547
Proved developed non-producing	3,240	89	3,255	44
Proved undeveloped	27,386	53,861	36,363	613
Total proved	98,645	108,118	116,665	$ 2,204
Standardized Measure(2)				$ 2,204
Pro Forma Standardized Measure(2)				$ 1,397

(1) PV-10 is a non GAAP financial measure and generally differs from Standardized Measure, the most directly comparable GAAP financial measure, because it does not include the effects of income taxes on future net revenues. However, our PV-10 and our Standardized Measure are equivalent because we are a subchapter S-corporation. In connection with the closing of this offering, we will convert to a subchapter C-corporation. Our pro-forma Standardized Measure, assuming our conversion to a subchapter C-corporation, was $1.4 billion at December 31, 2005. Neither PV-10 nor Standardized Measure represents an estimate of the fair market value of our oil and gas properties. We and others in the industry use PV-10 as a measure to compare the relative size and value of proved reserves held by companies without regard to the specific tax characteristics of such entities.

(2) As of December 31, 2005, Continental Resources was structured as a subchapter S-corporation. Accordingly, no provision for federal or state corporate income taxes has been provided because taxable income is passed through to our shareholders. Pro Forma Standardized Measure assumes Continental Resources was restructured as a subchapter C-corporation as of December 31, 2005.

The following table sets forth our estimated proved reserves, percent of total proved reserves that are proved developed and PV-10 as of December 31, 2005 by region:

	Oil (MBbls)	Gas (MMcf)	Total (MBoe)	% Proved developed	PV-10(1) (in millions)

Rocky Mountain:					
Red River units	61,881	34,980	67,711	75%	$ 1,215
Bakken field	22,262	10,671	24,041	45%	505
Other	8,468	3,587	9,065	64%	137
Mid-Continent	5,955	57,098	15,472	82%	328
Gulf Coast	79	1,782	376	100%	19
Total	98,645	108,118	116,665	69%	$ 2,204

(1) PV-10 is a non GAAP financial measure and generally differs from Standardized Measure, the most directly comparable GAAP financial measure, because it does not include the effects of income taxes on future net revenues. However, our PV-10 and our Standardized Measure are equivalent because we are a subchapter S-corporation. In connection with the closing of this offering, we will convert to a subchapter C-corporation. Our pro-forma Standardized Measure, assuming our conversion to a subchapter C-corporation, was $1.4 billion at December 31, 2005. Neither PV-10 nor Standardized Measure represents an estimate of the fair market value of our oil and gas properties. We and others in the industry use PV-10 as a measure to compare the relative size and value of proved reserves held by companies without regard to the specific tax characteristics of such entities.

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Production and Price History

The following table sets forth summary information concerning our production results, average sales prices and production costs for the years ended December 31, 2003, 2004 and 2005 and the nine months ended September 30, 2005 and 2006:

	Year ended December 31,			Nine months ended September 30,	
	2003	2004	2005	2005	2006
Net production volumes:					
Oil (MBbls)(1)	3,463	3,688	5,708	4,045	5,454
Natural gas (MMcf)	10,751	8,794	9,006	6,748	6,755
Oil equivalents (MBoe)	5,255	5,154	7,209	5,170	6,580
Average prices(1):					
Oil, without hedges ($/Bbl)	$ 28.88	$ 38.85	$ 52.45	$ 51.90	$ 58.05
Oil, with hedges ($/Bbl)	25.98	37.12	52.45	51.90	58.05
Natural gas ($/Mcf)	4.55	5.06	6.93	6.17	6.22
Oil equivalents, without hedges ($/Boe)	28.35	36.45	50.19	48.67	54.50
Oil equivalents, with hedges ($/Boe)	26.44	35.20	50.19	48.67	54.50
Costs and expenses(1):					
Production expense ($/Boe)	$ 7.77	$ 8.49	$ 7.32	$ 7.40	$ 7.03
Production tax ($/Boe)	1.95	2.39	2.22	2.11	2.53
General and administrative ($/Boe)	1.83	2.41	4.34	4.81	3.02
DD&A expense ($/Boe)(2)	7.10	7.02	6.50	6.26	6.69

(1) Oil sales volumes are 10 MBbls less than oil production volumes for the nine months ended September 30, 2006. Average prices and per unit costs have been calculated using sales volumes.
(2) Rate is determined based on DD&A expense derived from oil and natural gas assets.

The following table sets forth information regarding our average daily production during the third quarter of 2006:

	Average daily production Third quarter 2006		
	Bbls	Mcf	Boe
Rocky Mountain			
Red River units	10,978	1,104	11,162
Bakken field	7,014	4,715	7,800
Other	1,380	1,438	1,620
Mid-Continent	1,754	14,895	4,236
Gulf Coast	226	3,517	812
Total	21,352	25,669	25,630

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Productive Wells

The following table presents the total gross and net productive wells by region and by oil or gas completion as of December 31, 2005:

	Oil wells		Natural gas wells		Total wells	
	Gross	Net	Gross	Net	Gross	Net
Rocky Mountain:						
Red River units	199	187			199	187
Bakken field	60	34			60	34
Other	262	230			262	230
Mid-Continent	664	514	209	116	873	630
Gulf Coast	7	5	33	18	40	23
Total	1,192	970	242	134	1,434	1,104

Gross wells are the number of wells in which a working interest is owned and net wells are the total of our fractional working interests owned in gross wells. As of December 31, 2005, we owned interests in no wells containing multiple completions.

Developed and Undeveloped Acreage

The following table presents the total gross and net developed and undeveloped acreage by region as of December 31, 2005:

	Developed acres		Undeveloped acres		Total acres	
	Gross	Net	Gross	Net	Gross	Net
Rocky Mountain:						
Red River units	144,176	128,047			144,176	128,047
Bakken field	52,421	38,971	588,081	356,426	640,502	395,397
Other	45,720	36,153	358,649	208,612	404,369	244,765
Mid-Continent	152,734	99,279	115,746	73,582	268,480	172,861
Gulf Coast	41,842	11,890	23,598	7,873	65,440	19,763
Total	436,893	314,340	1,086,074	646,493	1,522,967	960,833

The following table sets forth the number of gross and net undeveloped acres as of December 31, 2005 that will expire over the next three years by region unless production is established within the spacing units covering the acreage prior to the expiration dates:

	2006		2007		2008	
	Gross	**Net**	**Gross**	**Net**	**Gross**	**Net**
Rocky Mountain:						
Red River units						
Bakken field	19,778	11,897	108,311	68,395	200,966	113,166
Other	89,913	59,710	72,339	46,106	43,600	30,141
Mid-Continent	28,710	19,911	10,581	7,563	23,888	14,519
Gulf Coast	3,407	2,404	1,636	1,150	15,319	3,065
Total	141,808	93,922	192,867	123,214	283,773	160,891

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Drilling Activity

During the three years ended December 31, 2005, we drilled exploratory and development wells as set forth in the table below:

	2003		2004		2005	
	Gross	**Net**	**Gross**	**Net**	**Gross**	**Net**
Exploratory wells:						
Oil	6	4.1	12	5.6	13	5.9
Gas	7	3.5	5	0.9	2	1.3
Dry	7	5.5	17	10.5	11	6.9
Total exploratory wells	20	13.1	34	17.0	26	14.1
Development wells:						
Oil	11	6.9	14	8.3	50	30.6
Gas	14	9.6	13	5.7	15	7.6
Dry	4	3.7	4	2.6	3	3.0
Total development wells	29	20.2	31	16.6	68	41.2
Total wells	49	33.3	65	33.6	94	55.3

As of December 31, 2005, there were 20 gross (10.6 net) development wells and 5 gross (3.0 net) exploratory wells in the process of drilling. As of April 30, 2006, 19 gross (9.8 net) wells of the development wells in process as of December 31, 2005, were completed as producers and the remaining development well was completed as a dry hole. As of September 30, 2006, 3 gross (1.5 net) wells of the exploratory wells in process as of December 31, 2005 were completed as producers, 1 gross (1 net) well was completed as a dry hole and the remaining exploratory well was in the process of completion.

As of November 14, 2006, we operated 18 rigs on our properties and have plans to add additional rigs during the next six months. There can be no assurance, however, that additional rigs will be available to us at an attractive cost. See Risk Factors The unavailability or high cost of additional drilling rigs, equipment, supplies, personnel and oilfield services could adversely affect our ability to execute our exploration and development plans within our budget and on a timely basis.

Summary of Oil and Natural Gas Properties and Projects

Rocky Mountain Region

Our properties in the Rocky Mountain region represented 84% of our PV-10 as of December 31, 2005. During the three months ended September 30, 2006, our average production from such properties was 19,373 net Bbls of oil and 7,257 net Mcf of natural gas per day. Our principal producing properties in this region are in the Red River units, the Bakken field and the Big Horn Basin. Additionally, we have prospective acreage for the Lewis Shale in southern Wyoming and the Pierre Shale in western North Dakota, other unconventional resource plays in the Rocky Mountain Region.

For the six month period ended August 31, 2006, we ranked second among all oil companies in terms of gross operated crude oil production within the Rocky Mountain states of Montana, North Dakota, South Dakota and Wyoming.

Red River Units

Our Red River units represented 65% of our PV-10 in the Rocky Mountain Region as of December 31, 2005 and 54% of our average daily Rocky Mountain Region equivalent production for the three months ended September 30, 2006. The eight units comprising the Red River units are located along the Cedar Hills Anticline

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in North Dakota, South Dakota and Montana and produce oil and natural gas from the Red River B formation, a thin, continuous, dolomite formation at depths of 8,000 to 9,500 feet. Our Red River units comprise a portion of the Cedar Hills field, listed by the Energy Information Administration in 2004 as the 23rd largest field in the United States ranked by liquids proved reserves.

Cedar Hills Units. The Cedar Hills North unit (CHNU) is located in Bowman and Slope Counties, North Dakota. We drilled the initial horizontal well in the CHNU, the Ponderosa 1-15, in April 1995. As of December 31, 2005, we had drilled 146 horizontal wells within this 49,700-acre unit, with 78 producing wellbores and the remainder serving as injection wellbores. We operate and own a 98% working interest in the CHNU.

The Cedar Hills West unit (CHWU), in Fallon County, Montana, is contiguous to the northern portion of CHNU. As of December 31, 2005, this 7,800-acre unit contained ten horizontal producing wells and four HPAI wells. We operate and own a 100% working interest in the CHWU.

In January 2003, we commenced enhanced recovery in the two Cedar Hills units, with HPAI used throughout most of the area and water injected generally along the boundary of the CHNU. Under HPAI, compressed air injected into a reservoir oxidizes residual oil and produces flue gases (primarily carbon dioxide and nitrogen) that mobilize and sweep the crude oil into producing wellbores. In response to the HPAI and water injection, production from the Cedar Hills units increased to 8,561 net Boe per day in September 2006 from 2,185 net Boe per day in November 2003. As of December 31, 2005, the average density in the Cedar Hill units was approximately one producing wellbore each 653 acres. We currently plan to drill 111 new horizontal wellbores and 14 horizontal extensions of existing wellbores in the Cedar Hills units during the next two to three years, increasing the density of both the producing and injection wellbores. We believe this operation will increase production and sweep efficiency. Production in the two units, as projected by our proved reserves report for the year ended December 31, 2005, is expected to peak in 2009 at approximately 15,800 net Boe per day. In 2006, we plan to invest approximately $48 million drilling in the Cedar Hills units.

On November 8, 2005, we entered into a contract with Hiland Partners, LP (Hiland) for the processing and treatment of gas produced from the CHNU and CHWU. Under the terms of the contract we agree to deliver low pressure gas to Hiland for compression, treatment and processing at a facility to be constructed by Hiland. Nitrogen and carbon dioxide must be removed from the gas production associated with the increasing oil production from CHNU and CHWU for the gas production to be marketable. Under the terms of the contract, we pay $0.60 per Mcf in gathering and treating fees, and 50% of the electrical costs attributable to compression and plant operation and receive 50% of the proceeds from residue gas and plant product sales. After we deliver 36 Bcf of gas, the $0.60 per Mcf gathering and treating fee is eliminated. If the average composite volume of carbon dioxide is less than 10%, we pay an additional $0.10 per Mcf treating fee, otherwise the treating fee is $0.20 per Mcf. We currently plan to invest approximately $6 million during 2006 to construct gas gathering from each well to central tank battery delivery points. The plant is currently expected to be operational in February 2007.

Medicine Pole Hills Units. The Medicine Pole Hills units (MPHU) are approximately five miles east of the southern portion of the CHNU. We acquired the Medicine Pole Hills unit in 1995. At that time, the 9,600- acre unit consisted of 18 vertical producing wellbores and four injection wellbores under HPAI producing 525 net Bbls of oil per day. We have since drilled 30 horizontal wellbores extending production to the west with the formation of the 15,000-acre Medicine Pole Hills West unit and to the south, with the 11,500-acre Medicine Pole Hills South unit. All three units are under HPAI. We operate and own an average 77% working interest in the three units. Production from the units averaged 1,040 net Bbls of oil and 296 net Mcf of natural gas per day in September 2006. We currently plan to drill 20 new horizontal wellbores and nine horizontal extensions of existing wellbores during the next two years, increasing the density of both producing and injection wellbores. We believe these operations will increase production and sweep efficiency. In 2006, we plan to invest approximately $10 million for drilling in MPHU.

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Buffalo Red River Units. The three contiguous Buffalo Red River units (Buffalo, West Buffalo and South Buffalo) are located in Harding County, South Dakota, approximately 21 miles south of the MPHU. When we purchased the units in 1995, there were 73 vertical producing wellbores and 38 injection wellbores under HPAI producing approximately 1,906 net Bbls of oil per day. We operate and own an average working interest of 95% in the 32,900 acres comprising the three units. During 2005, we re-entered 11 existing vertical wells and drilled horizontal laterals to increase production and sweep efficiency. Production for the month of September 2006 was 1,311 net Bbls of oil per day compared to an average of 1,162 net Bbls of oil per day for the first half of 2005. We currently plan to drill 28 horizontal extensions of existing wellbores in the Buffalo Red River units over the next two years. We believe these operations will increase production and sweep efficiency. In 2006, we plan to invest $9 million for drilling in the Buffalo Red River units.

Bakken Field

Our properties within the Bakken field in Montana and North Dakota represented 27% of our PV-10 in the Rocky Mountain Region as of December 31, 2005 and 38% of our average daily Rocky Mountain Region equivalent production for the three months ended September 30, 2006. The Bakken formation is widespread and relatively uniform in development throughout the Montana and North Dakota portions of the Williston Basin. The Bakken formation consists of three lithologic members the upper shale, middle member and locally a lower shale. The shales are highly organic, thermally mature and overpressured and act as both a source and reservoir for the oil. The middle member is also productive locally and varies in composition from a silty dolomite, to shalely limestone or sand across the Williston Basin. Horizontal drilling and advanced fracture stimulation technologies have enabled commercial recovery from this historically non-commercial reservoir. Generally, the Bakken formation is drilled horizontally on 1,280-acre units to vertical depths ranging from 9,000 to 10,500 feet with opposing horizontal laterals each extending approximately 4,500 feet, for a total drilled footage of approximately 18,000 to 21,000 feet. The wells are typically fracture stimulated to maximize recovery and economic returns.

Richland County, Montana. Commercial production data available on wells completed after February 2001 in the Bakken formation by various operators in Richland County, Montana report 379 productive wells with cumulative production as of June 2006 of 36 MMBbls of oil and 21 Bcf of natural gas. Daily production from these wells for the month of June 2006 was approximately 50 MBbls of oil and 33 MMcf of natural gas.

Our initial well in the Richland County, Montana portion of the Bakken field, the Goss #34-26 completed in August 2003, has produced approximately 206,000 gross Bbls of oil and 100,000 gross Mcf of natural gas as of September 30, 2006 and averaged 96 gross Bbls of oil and 54 gross Mcf of natural gas per day during the month of September 2006. Cumulative production from the 71 operated wells drilled by us in Richland County was 6.7 gross MMBbls of oil and 3.4 gross Bcf of natural gas through September 30, 2006, with an average rate of 12,371 gross Bbls and 8,817 gross Mcf per day for the month of September 2006. Our average daily rate from operated and non-operated wells in this field (53 net wells) was approximately 6,973 net Bbls of oil and 5,019 net Mcf of natural gas during the month of September 2006. Substantially all of our wells have been horizontally drilled on 1,280-acre units within the middle dolomite member, which is well developed under our leasehold in Richland County. In 2006, we have drilled several second horizontal wells in 1,280-acre units and plan to drill a horizontal well in 2007 to test the incremental reserves of a third well in a 1,280-acre unit.

As of December 31, 2005, we held 129,000 gross (101,000 net) undeveloped acres in the Richland County, Montana portion of the Bakken field with 60 proved undeveloped and 138 additional scheduled drilling locations. We currently have four operated drilling rigs in this part of the field and plan to invest $78 million in the drilling of 40 horizontal Bakken wells in Montana during 2006.

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North Dakota Bakken. Encouraged by the results in Richland County, Montana, operators have begun drilling horizontal wells in the Bakken formation in North Dakota. Since this play is in the early stages of development, results are limited but encouraging. As of September 30, 2006, production data had been reported to the North Dakota Oil and Gas Commission on 79 horizontal North Dakota Bakken wells completed since March 2004. The initial production rates on the 79 wells ranged up to 1,369 Boe per day and averaged 193 Boe per day per well. Cumulative and daily production from the 79 wells as of September 30, 2006 was 1.7 MMBoe and 5,415 Boe, respectively.

As in Richland County, Montana, the upper Bakken shale in western North Dakota is highly organic, thermally mature and over-pressured. Within our North Dakota acreage, the formation is found at vertical depths ranging from 8,500 to 11,000 feet. In North Dakota, the Bakken formation gross interval ranges up to 130 feet compared to about 30 feet in Richland County, Montana. Similarly, the upper Bakken shale thickness ranges up to 20 feet in North Dakota compared to about 7 feet in Richland County, Montana. The middle dolomite member of the Bakken formation in the southern portion of our North Dakota acreage is similar to that present in the Richland County, Montana producing area. Moving north on our acreage, the middle dolomite member increases in thickness but diminishes in reservoir quality. We believe the loss of quality of the middle member is offset by the increasing thickness of the upper and lower shales as one moves north and the strategic position of our acreage along the axis of the Nesson anticline.

In March 2004, we served as contract operator on a well completed in the Bakken formation near the northern border of our acreage. We drilled a 4,376-foot single horizontal lateral within the middle dolomite member of the Bakken Shale in an abandoned dry hole. The well has produced approximately 39,000 gross Boe through September 30, 2006 and is estimated to ultimately produce approximately 213,000 gross Boe. The well, initially owned by our principal shareholder and his family, was acquired by us in August 2005.

In October 2004, we completed a well in the Bakken formation on the extreme southeastern edge of our North Dakota acreage in a well originally planned as a shallower Lodgepole formation test. This well is over 120 miles south of our initial test. The well was unsuccessful in the Lodgepole formation and was deepened to test the Bakken formation at this location. The middle dolomite member significantly thins along the southern edge of our acreage and, in this test well, the middle member was essentially not present. The well has produced approximately 16,000 gross Boe through September 30, 2006 from a single 6,199-foot horizontal lateral and is estimated ultimately to produce approximately 26,000 gross Boe.

In 2005, we participated with a small working interest in two non-operated Bakken formation tests in North Dakota. One is expected to ultimately produce about 50,000 gross Boe and the other, 230,000 gross Boe.

In 2006, we have participated in 7 gross (3.9 net) operated and 7 gross (1.2 net) non-operated horizontal Bakken Shale wells in North Dakota as of November 14, 2006. Of these, 3 gross (0.2 net) have been completed as producers, 8 gross (3.9 net) are drilled and awaiting completion and 3 gross (1 net) are being drilled. Initial production rates for the 3 producing wells were 208 Boe, 550 Boe and 1,360 Boe per day.

In June 2006, we entered into an agreement with ConocoPhillips Company to form an area of mutual interest (AMI) within Dunn, McKenzie, Mountrail and Williams Counties, North Dakota and jointly drill wells to test the Bakken formation. Within the AMI, we own approximately 97,000 net acres. Initial wells proposed under the agreement establish exploration blocks covering the 1,280-acre spacing unit for the initial well and two adjacent 1,280-acre spacing units. Each party has the right to acquire from the other party an undivided 50% interest in the exploration block acreage owned by the other party at $500 per net acre. ConocoPhillips Company has proposed and we have agreed to participate in the initial three wells to be drilled under the agreement. As of November 14, 2006, one well was producing, one well was drilled and awaiting completion and one well was being drilled.

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As of December 31, 2005, we held 459,000 gross (256,000 net) undeveloped acres in contiguous counties in North Dakota across the state border from the Richland County, Montana drilling activity. During 2006, we plan to invest approximately $19 million in the drilling of 11 horizontal Bakken wells on our acreage in North Dakota.

Big Horn Basin and Other

Our wells within the Big Horn Basin in northern Wyoming and other areas within the Rocky Mountain region represented 8% of our PV-10 in the Rocky Mountain Region as of December 31, 2005 and 8% of our average daily Rocky Mountain Region equivalent production for the three months ended September 30, 2006. During the three months ended September 30, 2006, we produced an average of 1,380 net Bbls of oil and 1,438 net Mcf of natural gas per day from our wells in the Big Horn Basin and other areas within the Rocky Mountain region. Our principal property in the Big Horn Basin, the Worland field, produces primarily from the Phosphoria formation. We have 44 additional proved undeveloped drilling locations in the Worland field. During 2006, we plan to invest approximately $6 million in the drilling of four Tensleep formation wells elsewhere in the Big Horn Basin.

Lewis Shale Project

As of December 31, 2005, we owned approximately 109,000 gross (28,000 net) undeveloped acres in the Washakie Basin in Carbon and Sweetwater Counties, Wyoming. Our objective is the Lewis Shale, a shale formation up to 1,500 feet thick with thin interbedded and discontinuous siltstones and sandstones. Underlying our acreage, the Lewis Shale is over-pressured, fractured and gas charged with the potential to develop into an economic unconventional gas resource play. Previous drilling in the area has encountered gas from the thick, fractured shale, but only the thin, isolated sands within the shale have been produced. As of August 2006, the Triton field, located in the center of our acreage block, has produced a total of 6.7 Bcf of natural gas from 5 wells with up to 40 feet of perforations in thin sands within the Lewis Shale. We plan to produce the entire Lewis Shale sequence with the expectation that ultimate recoveries per well will be greater than previous results.

During 2006, we have participated with 40% working interest in the drilling of three wells in the project. While drilling our first well, the CEPO 20-17, we encountered two productive sands within the Lewis Shale. As of November 10, 2006, the well was flowing 3,483 Mcf of natural gas per day with flowing pressures of 5,900 pound per square inch from one sand. The second sand encountered in the CEPO 20-17 tested at rates of 2,000 Mcf of natural gas per day with a flowing pressure of 1,000 pounds per square inch and will be produced at a later date. Our second well, the Neptune 13-11, began producing at a rate of 1,174 Mcf of natural gas per day from the Lewis Shale after fracture stimulation in early August, 2006 and as of November 5, 2006 was producing at a rate of 638 Mcf of natural gas per day. The third well in this project, the Barricade 44-1, is currently being completed.

Pierre Shale Project

We have shallow natural gas reserve potential from the Pierre Shale formation within the 57,500 gross (56,000 net) acres held by production within our Cedar Hills units. The Pierre Shale is a sand/shale sequence that produces biogenic gas from vertical depths of 1,200 to 2,000 feet. Our acreage is approximately one mile east of an area where a total of 71 wells have been completed in the Pierre Shale formation from September 2003 through June 2006. Daily production from these wells in June of 2006 was approximately 4,315 Mcf of natural gas. We have drilled four wells to date and are currently evaluating the results.

Mid-Continent Region

Our properties in the Mid-Continent Region represented 15% of our PV-10 as of December 31, 2005. During the three months ended September 30, 2006, our average production from such properties was 1,754 net

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Bbls of oil and 14,895 net Mcf of natural gas per day. Our principal producing properties in this region are located in the Anadarko Shelf of western Oklahoma and the Illinois Basin. We have also acquired acreage in three unconventional resource plays: the Woodford Shale, New Albany Shale and Floyd Shale.

Anadarko Shelf

Our properties within the Anadarko Basin represent 74% of our PV-10 in the Mid-Continent Region as of December 31, 2005 and 70% of our average daily Mid-Continent Region equivalent production for the three months ended September 30, 2006. Our wells within the Anadarko Basin produce from a variety of sands and carbonates in both stratigraphic and structural traps. In 2006, we plan to invest approximately $24 million in the drilling of 28 wells in the Anadarko Basin.

Illinois Basin

Our properties within the Illinois Basin represent 26% of the PV-10 in the Mid-Continent Region as of December 31, 2005 and 28% of our average daily Mid-Continent Region equivalent production for the three months ended September 30, 2006. Our wells within the Illinois Basin produce primarily crude oil from units comprised of shallow sand formations under water injection. In 2006, we plan to invest approximately $6 million in the drilling of 39 wells in the Illinois Basin.

Woodford Shale Project

We owned approximately 10,000 gross (5,000 net) undeveloped acres in Coal, Hughes and Pittsburg Counties, Oklahoma as of December 31, 2005. During the nine months ended September 30, 2006, we added to our acreage position and owned approximately 65,000 gross (26,000 net) acres in the Woodford Shale project at September 30, 2006. Our drilling objective is the 100 to 175-foot thick Woodford Shale at vertical depths of 6,000 to 12,500 feet. We believe horizontal drilling, combined with advanced fracture stimulation technology, may provide the means for commercial development of this organic rich, gas-bearing shale. This play is in the early stages of development and data is limited. However, we are encouraged by recent drilling results. A total of 44 horizontal Woodford Shale completions have been reported within Coal, Hughes and Pittsburg Counties during the past two years with reported initial production rates ranging from 216 to 8,700 Mcf of natural gas per day. The number of rigs drilling horizontal Woodford wells in these counties has increased to 25 as of November 14, 2006. During 2006, we have participated in 3 gross (0.7 net) operated and 24 gross (1.5 net) non-operated horizontal Woodford Shale wells as of November 14, 2006. Of these 27 wells, 16 gross (1.0 net) wells have been completed as producers, 3 gross (0.4 net) are drilled and awaiting completion and 7 gross (0.8 net) are being drilled. Initial production rates for the 16 producing wells ranged from 1,021 Mcf to 8,700 Mcf of natural gas per day and averaged 3,350 Mcf of natural gas per day. We currently plan to add a second rig in the area in December 2006. In July 2006, we completed a 19 square mile 3D seismic survey over portions of our acreage to identify prospective drilling locations and anticipate investing approximately $9.0 million in the drilling of up to 30 Woodford Shale wells in 2006.

Marfa Basin Shale Project

In April 2006, we purchased a 50% working interest in approximately 135,000 acres in the Marfa Basin, a lightly explored basin located in Presidio and Brewster Counties, Texas. The Marfa Basin is geologically similar to other gas-prone basins along the Ouachita Overthrust belt, such as the Fort Worth and Arkoma Basins, and is located adjacent to the Delaware Basin where exploration for gas from Barnett equivalent shales is underway by several companies in Culberson County. We are targeting a highly organic and thermally mature sequence of shales up to 600 feet thick that contains Woodford and Barnett equivalent shales. There are no wells producing gas from these shales in the basin. In 2006, we plan to re-enter an existing cased wellbore to test the productivity

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of the shales and will develop plans for further development based on results. The cost of this re-entry is estimated at $1.0 million.

New Albany Shale Project

We owned approximately 36,000 gross (31,000 net) undeveloped acres in Kentucky and Indiana as of December 31, 2005. Our drilling objective is the New Albany Shale, an organically rich, gas-bearing Devonian age shale equivalent to the prolific Antrim Shale in Michigan. The New Albany Shale averages 100 feet thick under our acreage and is found at vertical depths of 1,500 to 4,500 feet. We believe the potential exists for the New Albany Shale to be an economic unconventional natural gas resource play. In December 2005, we completed our initial horizontal well in the New Albany Shale as an uncommercial producer. We plan to use the core and production data from this well and drilling results of other operators in the play to develop our future drilling plans.

Floyd Shale Project

We owned approximately 13,000 gross (8,000 net) undeveloped acres in Monroe County, Mississippi as of December 31, 2005. Our drilling objective is the Floyd Shale, a Mississippian age, organically rich shale found throughout the Black Warrior Basin in Mississippi and Alabama. Natural gas is encountered while this shale is being drilled, and the formation may prove to be an economic unconventional natural gas resource play. Few wells have attempted to produce this shale in the Basin. The Floyd Shale ranges from 25 to 80 feet thick under our acreage and is found at vertical depths of 2,000 to 4,000 feet. In December 2005, we re-entered two vertical wells and fracture stimulated the Floyd Shale formation. The resulting production rates were uneconomic. We plan to continue to evaluate our acreage for future drilling opportunities and monitor industry activity in this area.

Gulf Coast Region

During the three months ended September 30, 2006, our average production from our Gulf Coast properties was 226 net Bbls of oil and 3,517 net Mcf of natural gas per day. Our principal producing properties in this region are located in South Texas and Louisiana. In 2006, we plan to invest approximately $6 million in the drilling of 9 wells in the Texas and Louisiana Gulf Coast.

Marketing and Major Customers

We principally sell our oil and natural gas production to end users, marketers and other purchasers that have access to nearby pipeline facilities. In areas where there is no practical access to pipelines, oil is transported by truck to storage facilities. Our marketing of oil and natural gas can be affected by factors beyond our control, the effects of which cannot be accurately predicted. For a description of some of these factors, see Risk factors Market conditions or operational impediments may hinder our access to oil and natural gas markets or delay our production.

For the year ended December 31, 2005, oil sales to Plains Marketing, L.P., Banner and Nexen Marketing U.S.A. Inc. accounted for approximately 31%, 19% and 10%, respectively, of our total oil and natural gas sales. For the nine months ended September 30, 2006, oil sales to Banner and Nexen Marketing U.S.A. Inc. accounted for 18% and 15%, respectively, of our total oil and natural gas sales. No other purchasers accounted for more than 10% of our total oil and gas sales. Banner was an affiliate of ours as described under Certain Relationships and Related Party Transactions. In February 2006, we decided to market the majority of our crude oil in the Rocky Mountain region directly or through a wholly owned subsidiary rather than through an affiliate, and, as Banner has existing contacts and relationships with crude oil purchasers, we decided to purchase Banner. On March 30, 2006, we acquired Banner for approximately $8.8 million, the book value of working capital, principally cash, accounts receivable, crude oil inventory and accounts payable. We believe that the loss of any

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of these purchasers would not have a material adverse effect on our operations, as there are a number of alternative crude oil purchasers in our producing regions.

Title to Properties

As is customary in the oil and gas industry, we initially conduct only a cursory review of the title to our properties on which we do not have proved reserves. Prior to the commencement of drilling operations on those properties, we conduct a thorough title examination and perform curative work with respect to significant defects. To the extent title opinions or other investigations reflect title defects on those properties, we are typically responsible for curing any title defects at our expense. We generally will not commence drilling operations on a property until we have cured any material title defects on such property. We have obtained title opinions on substantially all of our producing properties and believe that we have satisfactory title to our producing properties in accordance with standards generally accepted in the oil and gas industry. Prior to completing an acquisition of producing oil and natural gas leases, we perform title reviews on the most significant leases and, depending on the materiality of properties, we may obtain a title opinion or review previously obtained title opinions. Our oil and natural gas properties are subject to customary royalty and other interests, liens to secure borrowings under our credit facility, liens for current taxes and other burdens which we believe do not materially interfere with the use or affect our carrying value of the properties.

Competition

We operate in a highly competitive environment for acquiring properties, marketing oil and natural gas and securing trained personnel. Our competitors vary within the regions in which we operate, and some of our competitors may possess and employ financial, technical and personnel resources substantially greater than ours, which can be particularly important in the areas in which we operate. Those companies may be able to pay more for productive oil and natural gas properties and exploratory prospects and to evaluate, bid for and purchase a greater number of properties and prospects than our financial or personnel resources permit. In addition, shortages or the high cost of drilling rigs could delay or adversely affect our development and exploration operations. Our ability to acquire additional prospects and to find and develop reserves in the future will depend on our ability to evaluate and select suitable properties and to consummate transactions in a highly competitive environment. Also, there is substantial competition for capital available for investment in the oil and natural gas industry.

Regulation of the Oil and Natural Gas Industry

Regulation of Transportation of Oil

Sales of crude oil, condensate and natural gas liquids are not currently regulated and are made at negotiated prices. Nevertheless, Congress could reenact price controls in the future.

Our sales of crude oil are affected by the availability, terms and cost of transportation. The transportation of oil in common carrier pipelines is also subject to rate regulation. The Federal Energy Regulatory Commission, or the FERC, regulates interstate oil pipeline transportation rates under the Interstate Commerce Act. In general, interstate oil pipeline rates must be cost-based, although settlement rates agreed to by all shippers are permitted and market-based rates may be permitted in certain circumstances. Effective January 1, 1995, the FERC implemented regulations establishing an indexing system (based on inflation) for transportation rates for oil that allowed for an increase or decrease in the cost of transporting oil to the purchaser. A review of these regulations by the FERC in 2000 was successfully challenged on appeal by an association of oil pipelines. On remand, the FERC in February 2003 increased the index slightly, effective July 2001. Intrastate oil pipeline transportation

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rates are subject to regulation by state regulatory commissions. The basis for intrastate oil pipeline regulation, and the degree of regulatory oversight and scrutiny given to intrastate oil pipeline rates, varies from state to state. Insofar as effective interstate and intrastate rates are equally applicable to all comparable shippers, we believe that the regulation of oil transportation rates will not affect our operations in any way that is of material difference from those of our competitors.

Further, interstate and intrastate common carrier oil pipelines must provide service on a non-discriminatory basis. Under this open access standard, common carriers must offer service to all similarly situated shippers requesting service on the same terms and under the same rates. When oil pipelines operate at full capacity, access is governed by prorationing provisions set forth in the pipelines published tariffs. Accordingly, we believe that access to oil pipeline transportation services generally will be available to us to the same extent as to our competitors.

Regulation of Transportation and Sale of Natural Gas

Historically, the transportation and sale for resale of natural gas in interstate commerce have been regulated pursuant to the Natural Gas Act of 1938, the Natural Gas Policy Act of 1978 and regulations issued under those Acts by the FERC. In the past, the federal government has regulated the prices at which natural gas could be sold. While sales by producers of natural gas can currently be made at uncontrolled market prices, Congress could reenact price controls in the future. Deregulation of wellhead natural gas sales began with the enactment of the Natural Gas Policy Act. In 1989, Congress enacted the Natural Gas Wellhead Decontrol Act which removed all Natural Gas Act and Natural Gas Policy Act price and non-price controls affecting wellhead sales of natural gas effective January 1, 1993.

FERC regulates interstate natural gas transportation rates and service conditions, which affects the marketing of natural gas that we produce, as well as the revenues we receive for sales of our natural gas. Since 1985, the FERC has endeavored to make natural gas transportation more accessible to natural gas buyers and sellers on an open and non-discriminatory basis. The FERC has stated that open access policies are necessary to improve the competitive structure of the interstate natural gas pipeline industry and to create a regulatory framework that will put natural gas sellers into more direct contractual relations with natural gas buyers by, among other things, unbundling the sale of natural gas from the sale of transportation and storage services. Beginning in 1992, the FERC issued Order No. 636 and a series of related orders to implement its open access policies. As a result of the Order No. 636 program, the marketing and pricing of natural gas have been significantly altered. The interstate pipelines traditional role as wholesalers of natural gas has been eliminated and replaced by a structure under which pipelines provide transportation and storage service on an open access basis to others who buy and sell natural gas. Although the FERC s orders do not directly regulate natural gas producers, they are intended to foster increased competition within all phases of the natural gas industry.

In 2000, the FERC issued Order No. 637 and subsequent orders, which imposed a number of additional reforms designed to enhance competition in natural gas markets. Among other things, Order No. 637 effected changes in FERC regulations relating to scheduling procedures, capacity segmentation, penalties, rights of first refusal and information reporting. Most pipelines tariff filings to implement the requirements of Order No. 637 have been accepted by the FERC and placed into effect.

We cannot accurately predict whether the FERC s actions will achieve the goal of increasing competition in markets in which our natural gas is sold. Additional proposals and proceedings that might affect the natural gas industry are pending before the FERC and the courts. The natural gas industry historically has been very heavily regulated. Therefore, we cannot provide any assurance that the less stringent regulatory approach recently established by the FERC will continue. However, we do not believe that any action taken will affect us in a way that materially differs from the way it affects other natural gas producers.

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Gathering service, which occurs upstream of jurisdictional transmission services, is regulated by the states onshore and in state waters. Although its policy is still in flux, FERC has reclassified certain jurisdictional transmission facilities as non-jurisdictional gathering facilities, which has the tendency to increase our costs of getting gas to point of sale locations.

Intrastate natural gas transportation is also subject to regulation by state regulatory agencies. The basis for intrastate regulation of natural gas transportation and the degree of regulatory oversight and scrutiny given to intrastate natural gas pipeline rates and services varies from state to state. Insofar as such regulation within a particular state will generally affect all intrastate natural gas shippers within the state on a comparable basis, we believe that the regulation of similarly situated intrastate natural gas transportation in any states in which we operate and ship natural gas on an intrastate basis will not affect our operations in any way that is of material difference from those of our competitors. Like the regulation of interstate transportation rates, the regulation of intrastate transportation rates affects the marketing of natural gas that we produce, as well as the revenues we receive for sales of our natural gas.

Regulation of Production

The production of oil and natural gas is subject to regulation under a wide range of local, state and federal statutes, rules, orders and regulations. Federal, state and local statutes and regulations require permits for drilling operations, drilling bonds and reports concerning operations. All of the states in which we own and operate properties have regulations governing conservation matters, including provisions for the unitization or pooling of oil and natural gas properties, the establishment of maximum allowable rates of production from oil and natural gas wells, the regulation of well spacing, and plugging and abandonment of wells. The effect of these regulations is to limit the amount of oil and natural gas that we can produce from our wells and to limit the number of wells or the locations at which we can drill, although we can apply for exceptions to such regulations or to have reductions in well spacing. Moreover, each state generally imposes a production or severance tax with respect to the production and sale of oil, natural gas and natural gas liquids within its jurisdiction.

The failure to comply with these rules and regulations can result in substantial penalties. Our competitors in the oil and natural gas industry are subject to the same regulatory requirements and restrictions that affect our operations.

Environmental, Health and Safety Regulation

General. Our operations are subject to stringent and complex federal, state, local and provincial laws and regulations governing environmental protection, health and safety, including the discharge of materials into the environment. These laws and regulations may, among other things:

- require the acquisition of various permits before drilling commences;
- restrict the types, quantities and concentration of various substances that can be released into the environment in connection with oil and natural gas drilling, production and transportation activities;

- limit or prohibit drilling activities on certain lands lying within wilderness, wetlands and other protected areas; and

- require remedial measures to mitigate pollution from former and ongoing operations, such as requirements to close pits and plug abandoned wells.

These laws and regulations may also restrict the rate of oil and natural gas production below the rate that would otherwise be possible. The regulatory burden on the oil and gas industry increases the cost of doing business in the industry and consequently affects profitability. Additionally, Congress and federal and state

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agencies frequently revise environmental, health and safety laws and regulations, and any changes that result in more stringent and costly waste handling, disposal and cleanup requirements for the oil and gas industry could have a significant impact on our operating costs.

The following is a summary of some of the existing environmental, health and safety laws and regulations to which our business operations are subject.

Waste Handling. The Resource Conservation and Recovery Act, or RCRA, and comparable state statutes, regulate the generation, transportation, treatment, storage, disposal and cleanup of hazardous and non-hazardous wastes. Under the auspices of the federal Environmental Protection Agency, or EPA, the individual states administer some or all of the provisions of RCRA, sometimes in conjunction with their own, more stringent requirements. Drilling fluids, produced waters and most of the other wastes associated with the exploration, development and production of crude oil or natural gas are currently regulated under RCRA s non-hazardous waste provisions. However, it is possible that certain oil and natural gas exploration and production wastes now classified as non-hazardous could be classified as hazardous wastes in the future. Any such change could result in an increase in our costs to manage and dispose of wastes, which could have a material adverse effect on our results of operations and financial position.

Comprehensive Environmental Response, Compensation and Liability Act. The Comprehensive Environmental Response, Compensation and Liability Act, or CERCLA, also known as the Superfund law, imposes joint and several liability, without regard to fault or legality of conduct, in connection with the release of a hazardous substance into the environment. Persons potentially liable under CERCLA include the current or former owner or operator of the site where the release occurred and anyone who disposed or arranged for the disposal of a hazardous substance to the site where the release occurred. Under CERCLA, such persons may be subject to joint and several liability for the costs of cleaning up the hazardous substances that have been released into the environment, damages to natural resources and the costs of certain health studies. In addition, 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.

We currently own, lease or operate and have formerly owned, leased or operated numerous properties that have been used for oil and natural gas exploitation and production for many years. Although we believe that we have utilized operating and waste disposal practices that were standard in the industry at the time, hazardous substances may have been released on, at or under the properties owned, leased or operated by us, or on, at or under other locations, including off-site locations, where such substances have been taken for disposal. In addition, some of our properties have been operated by third parties or by previous owners or operators whose handling, treatment and disposal of hazardous substances were not under our control. These properties and the substances disposed or released on, at or under them may be subject to CERCLA, RCRA and analogous state laws. Pursuant to such laws, we have in the past performed remediation of spills and releases resulting from our operations. In certain circumstances, we could be required to remove previously disposed substances and wastes, remediate contaminated property or perform remedial plugging or pit closure operations to prevent future contamination. In addition, federal and state trustees can also seek substantial compensation for damages to natural resources resulting from spills or releases.

Water Discharges. The Federal Water Pollution Control Act, or the Clean Water Act, and analogous state laws, impose restrictions and strict controls with respect to the discharge of pollutants, including oil and other substances generated by our operations, into waters of the United States or state waters. Under these laws, the discharge of pollutants into regulated waters is prohibited except in accordance with the terms of a permit issued by the EPA or an analogous state agency. Federal and state regulatory agencies can impose administrative, civil and criminal penalties for non-compliance with discharge permits or other requirements of the Clean Water Act and analogous state laws and regulations.

The Safe Drinking Water Act, or SDWA, and analogous state laws impose requirements relating to our underground injection activities. Under these laws, the EPA and state environmental agencies have adopted regulations relating to permitting, testing, monitoring, record-keeping and reporting of injection well activities, as well as prohibitions against the migration of injected fluids into underground sources of drinking water. We currently own and operate a number of injection wells, used primarily for re-injection of produced waters, that are subject to SDWA requirements.

Air Emissions. The Federal Clean Air Act and comparable state laws regulate emissions of various air pollutants through air emissions permitting programs and the imposition of other requirements. In addition, EPA and certain states in which we operate have developed and continue to develop stringent regulations governing emissions of toxic air pollutants at specified sources. Federal and state regulatory agencies can impose administrative, civil and criminal penalties for non-compliance with air permits or other requirements of the Federal Clean Air Act and analogous state laws and regulations.

The Kyoto Protocol to the United Nations Framework Convention on Climate Change became effective in February 2005. Under the Protocol, participating nations are required to implement programs to reduce emissions of certain gases, generally referred to as greenhouse gases, that are suspected of contributing to global warming. The United States is not currently a participant in the Protocol, and Congress has not acted upon recent proposed legislation directed at reducing greenhouse gas emissions. However, there has been support in various regions of the country for legislation that requires reductions in greenhouse gas emissions, and some states have already adopted legislation addressing greenhouse gas emissions from various sources, primarily power plants. The oil and natural gas industry is a direct source of certain greenhouse gas emissions, namely carbon dioxide and methane, and future restrictions on such emissions could impact our future operations. At this time, it is not possible to accurately estimate how potential future laws or regulations addressing greenhouse gas emissions would impact our business.

National Environmental Policy Act. Oil and natural gas exploration and production activities on federal lands are subject to the National Environmental Policy Act, or NEPA. NEPA requires federal agencies, including the Department of Interior, to evaluate major agency actions that have the potential to significantly impact the environment. In the course of such evaluations, an agency will prepare an Environmental Assessment that assesses the potential direct, indirect and cumulative impacts of a proposed project and, if necessary, will prepare a more detailed Environmental Impact Statement that may be made available for public review and comment. All of our current exploration and production activities, as well as proposed exploration and development plans, on federal lands require governmental permits that are subject to the requirements of NEPA. This process has the potential to delay the development of oil and natural gas projects.

Health, Safety and Disclosure Regulation. We are subject to the requirements of the federal Occupational Safety and Health Act, or OSHA, and comparable state statutes. The OSHA hazard communication standard, the Emergency Planning and Community Right to Know Act and similar state statutes require that we organize and/or disclose information about hazardous materials stored, used or produced in our operations.

We have incurred in the past, and expect to incur in the future, capital and other expenditures related to environmental compliance. Such expenditures, however, are included within our overall capital and operating budgets and are not separately accounted for. Although we believe that our continued compliance with existing requirements will not have a material adverse impact on our financial condition and results of operations, we cannot assure you that the passage of more stringent laws or regulations in the future will not have an negative impact on our financial position or results of operations.

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Employees

As of September 30, 2006, we employed 298 people, including 163 employees in drilling and production, 43 in financial and accounting, 25 in land, 17 in exploration, 12 in reservoir engineering, 27 in administrative and 11 in information technology. Our future success will depend partially on our ability to attract, retain and motivate qualified personnel. We are not a party to any collective bargaining agreements and have not experienced any strikes or work stoppages. We consider our relations with our employees to be satisfactory. From time to time we utilize the services of independent contractors to perform various field and other services.

Legal Proceedings

We are not a party to any material pending legal proceedings, other than ordinary course litigation incidental to our business. While the ultimate outcome and impact of any proceeding cannot be predicted with certainty, our management believes that the resolution of any proceeding will not have a material adverse effect on our financial condition or results of operations.

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Management

Executive Officers and Directors

The following table sets forth names, ages and titles of our executive officers and directors:

Name	Age	Title
Harold G. Hamm(1)(3)	60	Chairman, Chief Executive Officer and Director
Mark E. Monroe(5)	52	President, Chief Operating Officer and Director
John D. Hart	39	Vice President, Chief Financial Officer and Treasurer
Jeffrey B. Hume	55	Senior Vice President Operations
Tom E. Luttrell	48	Senior Vice President Land
Jack H. Stark(4)	52	Senior Vice President Exploration and Director
Richard H. Straeter	48	President Illinois Division
Robert J. Grant(2)(5)	68	Director
George S. Littell(3)	62	Director
Lon McCain(1)(2)(5)	58	Director
H. R. Sanders, Jr.(1)(2)(4)	74	Director

(1) Member of the compensation committee.

(2) Member of the audit committee.

(3) Term expires in 2007.

(4) Term expires in 2008.

(5) Term expires in 2009.

Harold G. Hamm has served as Chief Executive Officer and a director since our inception in 1967 and currently serves as Chairman of the board of directors. He serves as Chairman of the board of directors of the general partner of Hiland Partners LP, one of our affiliates and a NASDAQ publicly traded midstream master limited partnership, and he serves as Chairman of the board of directors of the general partner of Hiland Holdings GP, LP (Hiland Holdings), also publicly traded on NASDAQ. Hiland Holdings owns the general partner interest and units in Hiland

Partners LP. He also serves as a director of Complete Production Services, Inc., an NYSE publicly traded oil and gas service company. Mr. Hamm serves as Chairman of the Oklahoma Independent Petroleum Association and serves on the Board of the Oklahoma Energy Explorers. He was President of the National Stripper Well Association and founder and Chairman of Save Domestic Oil, Inc.

Mark E. Monroe became President and Chief Operating Officer in October 2005 and has served as a board member since November 2001. He was Chief Executive Officer and President of Louis Dreyfus Natural Gas Corp. prior to its merger with Dominion Resources, Inc. in October 2001. Prior to the formation of Louis Dreyfus Natural Gas Corp. in 1990, he was Chief Financial Officer of Bogert Oil Company. He has served as Chairman of the Oklahoma Independent Petroleum Association, served on the Domestic Petroleum Council and the National Petroleum Council and on the boards of the Independent Petroleum Association of America, the Oklahoma Energy Explorers and the Petroleum Club of Oklahoma City. For two years prior to his election as President and Chief Operating Officer, he served as a board member of Unit Corporation, an NYSE publicly traded onshore drilling and oil and gas exploration and production company. Mr. Monroe is a Certified Public Accountant and received his Bachelor of Business Administration degree from the University of Texas at Austin.

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John D. Hart became Vice President, Chief Financial Officer and Treasurer in November 2005. Mr. Hart has fourteen years of experience in public accounting, most recently as Senior Audit Manager with Ernst & Young LLP in Oklahoma City, Oklahoma. He is a member of the American Institute of Certified Public Accountants and the Oklahoma Society of Certified Public Accountants. Mr. Hart graduated from Oklahoma State University with a Masters of Science in Accounting in 1991.

Jeffrey B. Hume became our Senior Vice President of Operations in November 2006. He was previously elected as Senior Vice President of Resource and Business Development in October 2005, Senior Vice President of Resource Development in July 2002 and served as Vice President of Drilling Operations from 1996 to 2002. Prior to joining us in May 1983 as Vice President of Engineering and Operations, Mr. Hume held various engineering positions with Sun Oil Company, Monsanto Company and FCD Oil Corporation. Mr. Hume is a Registered Professional Engineer and member of the Society of Petroleum Engineers, Oklahoma Independent Petroleum Association and the Oklahoma and National Professional Engineering Societies. Mr. Hume graduated from Oklahoma State University with a Bachelor of Science degree in Petroleum Engineering Technology in 1975.

Tom E. Luttrell joined us as Senior Landman in April 1991 and was promoted to Senior Vice President Land in February 1997. Prior to joining us, Mr. Luttrell was a Senior Landman for Alexander Energy Corp. and Pacific Enterprises Oil Corp. Mr. Luttrell is currently Chairman of the Northern Alliance of Independent Producers and a member of the Oklahoma Independent Petroleum Association legislative affairs committee. He is also a member of the Oklahoma Energy Explorers, American Association of Petroleum Landmen and several regional landman associations. Mr. Luttrell graduated from East Central Oklahoma State University in 1980 with a Bachelor of Business Administration.

Jack H. Stark became Senior Vice President Exploration and a director in May 1998. Prior to joining us as Vice President of Exploration in June 1992, he was the exploration manager for the Western Mid-Continent Region for Pacific Enterprises. From 1978 to 1988, he held various staff and middle management positions with Cities Service Co. and TXO Production Corp. He is a member of the American Association of Petroleum Geologists, Oklahoma Independent Petroleum Association, Rocky Mountain Association of Geologists, Houston Geological Society and Oklahoma Geological Society. Mr. Stark holds a Masters degree in Geology from Colorado State University.

Richard H. Straeter became President Illinois Division in October 2006. He was previously elected as President of Continental Resources of Illinois, Inc. (CRII) in April 2002. Prior to joining CRII, Mr. Straeter was employed by Barger Engineering, Inc. for 18 years as an engineering consultant and Vice President. He is a Registered Professional Engineer in Indiana, Illinois, Kentucky and Tennessee. Mr. Straeter is a past Chairman of the Illinois Basin Society of Petroleum Engineers and serves as a member of the National Petroleum Council, the Illinois Oil & Gas Association Board and the Ohio, Indiana, Kentucky and Michigan Oil and Gas Associations. Mr. Straeter earned his Bachelor of Science degree in Petroleum Engineering in 1983 and a Professional Engineering Degree (Honorary Masters) in 2004 from the University of Missouri-Rolla.

Robert J. Grant has been a director since January 2006. He was an audit partner of Deloitte & Touche LLP and a predecessor firm from 1969 to 2000. He served as partner in charge of the Dallas, Texas office audit department for ten years and a member of the firm s audit management group for twelve years. He has been a member of the Independent Petroleum Association of America, the American Petroleum Institute and the Texas Independent Producers and Royalty Owners Association and currently is a member of the American Institute of Certified Public Accountants and the Texas Society of Certified Public Accountant. Mr. Grant graduated from the University of Detroit with a MBA and BA in accounting.

George S. Littell has been a director since November 2004. He is a partner in the firm of Groppe, Long & Littell, a petroleum consulting firm. Prior to joining the firm in 1975, he held various positions in the natural gas,

refining, supply and distribution and gas liquids departments of Mobil Oil Corporation. Mr. Littell received a Bronze Star for his service as an officer in the US Army, Vietnam in 1968-1969. He is a member of the International Association for Energy Economics, an Eagle Scout and a director of the Sam Houston Area Council for the Boy Scouts of America. Mr. Littell graduated from Yale University in 1966 and earned an MBA degree from New York University and a law degree from La Salle Extension University.

Lon McCain has been a director since February 2006. He was Vice President, Treasurer and Chief Financial Officer of Westport Resources Corporation, a publicly traded exploration and production company, from 2001 until the sale of Westport to Kerr McGee Corporation in 2004. From 1992 until joining Westport in 2001, Mr. McCain was Senior Vice President and Principal of Petrie Parkman & Co., an investment banking firm specializing in the oil and gas industry. From 1978 until joining Petrie Parkman, Mr. McCain held senior financial management positions with Presidio Oil Company, Petro-Lewis Corporation and Ceres Capital. He was an Adjunct Professor of Finance at the University of Denver from 1982 through 2005. Mr. McCain currently serves on the board of Crimson Exploration, Inc., a domestic exploration and production company traded on the OTC Bulletin Board, and TransZap, Inc., a privately held provider of accounting software. Mr. McCain received a Bachelor of Business Administration and a Masters of Business Administration/Finance from the University of Denver.

H. R. Sanders, Jr. has been a director since November 2001. He served as a board member of Devon Energy Corporation from 1981 through 2000. In addition, he held the position of Executive Vice President for Devon Energy from 1981 until his retirement in 1997. From 1970 to 1981, Mr. Sanders was a Senior Vice President for Republic Bank of Dallas, N.A. with direct responsibility for independent oil, gas and mining loans. Mr. Sanders is a former member of the Independent Petroleum Association of America, Texas Independent Producers and Royalty Owners Association and Oklahoma Independent Petroleum Association, and a former director of Triton Energy Corporation. He currently serves on the board of Toreador Resources Corporation, a NASDAQ publicly traded oil and gas company with principal operations in France, Romania and Turkey.

Governance Matters

Our board of directors currently consists of seven members. Our directors are divided into three classes serving staggered three-year terms. Class I, Class II and Class III directors will serve until our annual meetings of shareholders in 2007, 2008 and 2009, respectively. At each annual meeting of shareholders, directors will be elected to succeed the class of directors whose terms have expired. This classification of our board of directors could have the effect of increasing the length of time necessary to change the composition of a majority of the board of directors. In general, at least two annual meetings of shareholders will be necessary for shareholders to effect a change in a majority of the members of the board of directors.

After the closing of this offering, we will be a controlled company within the meaning of the listing standards of the NYSE. Consequently, we will not be required to comply with certain of the NYSE s listed company requirements, such as the requirement to have a majority of independent directors on our board or the requirement to have compensation and governance committees comprised entirely of independent directors. However, we will still be required to have an independent audit committee under the NYSE s listed company requirements and will still be subject to SEC rules and regulations governing audit committees. As such, we will be required to have an audit committee consisting of independent directors as defined under the listing standards of the NYSE and under SEC rules and regulations. In addition, at least one member of the audit committee of our board of directors must meet the definition of an audit committee financial expert as defined under the SEC rules and regulations.

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Board Committees

Our board of directors currently has an audit committee and a compensation committee. Our board may establish other committees from time to time to facilitate our management. Our full board will be responsible for overseeing director nomination and other governance functions.

Audit Committee. The principal functions of the audit committee are to assist the board in monitoring the integrity of our consolidated financial statements, the independent auditor s qualifications and independence, the performance of our independent auditors and our compliance with legal and regulatory requirements. The audit committee will have the sole authority to retain and terminate our independent auditors and to approve the compensation paid to our independent auditors. The audit committee also will be responsible for overseeing our internal audit function. The audit committee currently consists of Messrs. Grant, McCain and Sanders, with Mr. Grant acting as the Chairman. Messrs. Grant, McCain and Sanders are independent under the listing standards of the NYSE and under SEC rules and regulations.

Compensation Committee. The principal functions of the compensation committee are to determine awards to employees of stock or other equity compensation, establish performance criteria for and evaluate the performance of the chief executive officer and approve compensation of all senior executives and directors. The compensation committee is currently comprised of Messrs. Hamm, McCain and Sanders, with Mr. Sanders acting as the Chairman.

Compensation Committee Interlocks and Insider Participation

None of our executive officers has served as a member of a compensation committee (or if no committee performs that function, the board of directors) of any other entity that has an executive officer serving as a member of our board of directors.

Director Compensation

Directors who are not employees of us are paid an annual retainer of $25,000 and $1,500 for each regular board of directors meeting attended. The Chairman of the Audit Committee is paid an additional annual retainer of $10,000, each Chairman of the other committees is paid an annual retainer of $2,500 and committee members other than the Chairman are paid an additional retainer of $1,000. A fee of $750 is paid for each special board meeting and $500 for each committee meeting attended.

Non-management directors are also annually granted restricted stock with an approximate market value of $40,000 to vest over one year. In January 2006, 3,300 shares of restricted stock were granted each to Messrs. Grant, Littell and Sanders. In February 2006, 3,300 shares of restricted stock were granted to Mr. McCain.

During 2005, we paid Mr. Monroe $22,250 for his service on our board of directors prior to his election as President and Chief Operating Officer.

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Executive Officer Compensation

Summary Compensation Table

The following table sets forth the compensation of our Chief Executive Officer and each of our other four most highly compensated executive officers serving as of December 31, 2005 for the year ended December 31, 2005. We refer to these five individuals collectively as the named executive officers.

			Annual compensation			Long-term compensation		
Name	**Title**	**Year**	**Salary**	**Bonus**	**Other Annual Compen-sation(1)**	**Restricted Stock Awards(2)**	**Number of Securities Underlying Options**	**All Other Compen-sation(3)**
Harold G. Hamm	Chairman and Chief Executive Officer	2005	$ 350,000	$ 200,000	$ 46,300	$ 2,948,400		$ 10,500
Jeffrey B. Hume	Senior Vice President Resource and Business Development	2005	$ 197,538	$ 136,250		$ 442,260		$ 9,877
Tom E. Luttrell	Senior Vice President Land	2005	$ 165,154	$ 111,916			165,000	$ 8,258
Gerald B. Smith(4)	Senior Vice President Drilling and Production	2005	$ 233,846	$ 136,974				$ 10,500
Jack H. Stark	Senior Vice President Exploration	2005	$ 214,231	$ 139,708		$ 442,260		$ 10,500

(1) Other annual compensation includes the aggregate incremental cost of personal benefits which exceeds the lesser of (i) $50,000 or (ii) 10% of the total amount of annual salary and bonus for any named executive officer. The amount includes for Mr. Hamm $30,200 for the personal use of company aircraft and $16,100 for the personal use of company cars.

(2) The restricted stock awards issued to Messrs. Hamm, Hume and Stark of 220,000 shares, 33,000 shares and 33,000 shares, respectively, vest ratably over three years. The value of these shares has been determined based on the formula set forth in the award agreements based on the book value of our shareholders equity adjusted for quarter-end reserve valuations.

(3) All other compensation represents the contributions made by us under our 401(k) Plan.

(4) Mr. Smith resigned from the Company in November 2006.

Stock Options Granted During 2005

The following table sets forth information regarding stock options granted to the named executive officers in the year ended December 31, 2005:

	Individual grants				Potential realizable value at assumed annual rates of stock price appreciation for option term		
Name	**Number of securities underlying options(1)**	**% of Total options granted to employees in fiscal year**	**Exercise price(2)**	**Expiration date**	**0%($)**	**5%($)**	**10%($)**
Tom E. Luttrell	165,000	60.0%	$ 5.71	5/1/2015		$ 592,607	$ 1,501,784

(1) On May 1, 2005, we granted Mr. Luttrell an option to acquire 165,000 shares of our common stock. The option vests ratably over three years or immediately upon a change in control and expires after ten years from the date of grant but may expire earlier upon termination of employment.

(2) The exercise price reflects the formula-derived value of our common stock on the date of grant.

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Stock Options Held at December 31, 2005

The following table sets forth certain information regarding stock options that the named executive officers held at December 31, 2005. None of the named officers exercised stock options during 2005.

	Shares of common stock covered by unexercised options(1)		Value of in-the-money unexercised options(2)	
Name	**Exercisable**	**Unexercisable**	**Exercisable**	**Unexercisable**
Jeffrey B. Hume	352,000			
Tom E. Luttrell	154,000	121,000		
Gerald B. Smith(3)	146,663	73,337		
Jack H. Stark	440,000			

(1) Options vest ratably over three years or upon a change in control. All options expire ten years from the date of grant, but also may expire earlier upon termination of employment.

(2) Values are calculated by multiplying the number of shares of common stock issuable upon the exercise of the options by the difference between the assumed initial public offering price of $ and the per share option exercise price.

(3) Mr. Smith resigned from the Company in November 2006.

Indemnification Agreements

All of our directors and officers have entered into customary indemnification agreements with us, pursuant to which we have agreed to indemnify our directors and officers to the fullest extent permitted by law.

Employee Benefit Plans

2005 Long-Term Incentive Plan

General. In October 2005 and as amended in April 2006, our board of directors and shareholders adopted and approved the Continental Resources, Inc. 2005 Long-Term Incentive Plan (the 2005 Plan). The purpose of the 2005 Plan is to provide our directors and our employees, advisors and consultants additional incentives that are designed to motivate them to put forth maximum effort toward the success and growth of the company and to enable the company and our affiliates to attract and retain experienced individuals. The 2005 Plan provides for the granting of incentive stock options intended to qualify under Section 422 of the Code, options that do not constitute incentive stock options, restricted stock awards, stock appreciation rights, performance units and performance bonuses.

Administration. Our board of directors has appointed the compensation committee thereof to administer the 2005 Plan. In general, the compensation committee is authorized to select the recipients of awards, establish the terms and conditions of those awards, accelerate the vesting, exercise or payment of an award or the performance period of an award, and determine to what extent a performance bonus may be deferred. In connection with the adoption of the 2005 Plan, our board of directors terminated our 2000 Stock Option Plan, described below.

Shares Subject to the 2005 Plan and Award Limits. The number of shares of our common stock that may be issued under the 2005 Plan may not exceed 5,500,000, subject to adjustment as described below. Shares of common stock that are attributable to awards that have expired, terminated or been canceled or forfeited, or have otherwise terminated without the issuance of an award, are available for issuance or use in connection with future awards. The maximum number of shares of common stock that may be subject to options and stock appreciation rights granted under the 2005 Plan to any one individual during any calendar year may not exceed 220,000 shares. The maximum number of shares of common stock that may be subject to restricted stock awards and

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performance unit awards granted under the 2005 Plan to any one individual during any calendar year may not exceed 220,000 shares. The maximum amount of compensation that may be paid under all performance bonuses under the 2005 Plan granted to any one individual during any calendar year may not exceed $1,000,000.

Options. The price at which a share of common stock may be purchased upon exercise of an option granted under the 2005 Plan, whether the option is an incentive stock option or an option that does not constitute an incentive stock option, will be determined by our board of directors or, with respect to awards granted to employees and consultants, the compensation committee, but the purchase price will not be less than the fair market value of a share of common stock on the date the option is granted. Options may be granted independently or in tandem with stock appreciation rights.

Stock Appreciation Rights. Our board of directors may grant stock appreciation rights independently of or in tandem with options to purchase common stock. A stock appreciation right allows the holder to receive, upon exercise of the right, an amount equal to the difference between the fair market value of the shares of our common stock on the exercise date and the exercise price stated in the award. The exercise price of a stock appreciation right can never be less than the fair market value of our common stock on the day of the award. The amount to be received upon exercise of a stock appreciation right will be paid in shares of our common stock.

Restricted Stock. Shares of common stock that are the subject of a restricted stock award under the 2005 Plan will be subject to restrictions on disposition by the holder of such award and an obligation of such holder to forfeit and surrender the shares to us under certain circumstances (the forfeiture restrictions). The forfeiture restrictions will be determined by our board of directors or the compensation committee, as applicable, and may provide that the forfeiture restrictions will lapse upon (a) continuous employment with, or in the case of an award granted to a director or consultant, service to, us or our affiliates, for a specified period of time, (b) the attainment of one or more operational, financial and/or stock performance criteria (the performance criteria) established by the board of directors or the compensation committee, as applicable, that are based on (1) reserve additions or replacements, (2) finding and development costs, (3) production volume, (4) production costs, (5) earnings (including net income or earnings before interest, taxes, depreciation and amortization (EBITDA)), (6) earnings per share, (7) cash flow, (8) operating income, (9) general and administrative expenses, (10) debt to equity ratio, (11) debt to cash flow ratio, (12) debt to EBITDA ratio, (13) EBITDA to interest ratio, (14) return on assets, (15) return on equity, (16) return on invested capital, (17) profit returns/margins, (18) stock price appreciation, (19) total shareholder return, and (20) relative stock price performance, or (c) a combination of any of the foregoing. In addition to acceleration of restricted stock awards upon a change of control of the company, our board of directors or compensation committee, as applicable, may provide that an award accelerates upon an eligible employee s retirement on or after his attainment of age 62, death or disability. Our board of directors may provide that a restricted stock award granted to a director or consultant will accelerate upon his resignation.

Performance Units. A performance unit award under the 2005 Plan is an award of a monetary unit that may be earned based on performance during a performance period of one year or more. At the time of the grant of a performance unit award, our board of directors or the compensation committee, as applicable, will establish the target, maximum and minimum value of each performance unit, the applicable performance criteria, and time period over which the performance will be measured. Payment of a performance unit award may be in cash or shares of common stock, as determined in the sole discretion of our board of directors.

Performance Bonuses. A performance bonus under the 2005 Plan is an award that provides for a payment that may be earned based on a performance during a period of one year or more. At the time of the grant of a performance bonus under the 2005 plan, our board of directors or the compensation committee, as applicable, will establish the amount that may be earned as a performance bonus under the award and the applicable performance criteria. Payment of a performance bonus award may be in cash or shares of common stock, as determined in the sole discretion of our board of directors or compensation committee, as applicable.

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Change of Control. All awards under the 2005 Plan become fully vested, fully earned and exercisable upon the occurrence of a change of control of the company, as defined in the 2005 Plan.

Amendment and Termination of the 2005 Plan and Awards. The maximum term of any award under the 2005 Plan is 10 years. No awards under the 2005 Plan may be granted after 10 years from its effective date (October 3, 2005). The 2005 Plan will remain in effect until all awards granted under the 2005 Plan have been settled. Our board of directors, in its discretion, may terminate the 2005 Plan at any time with respect to any shares of our common stock for which awards have not been granted. Our board of directors may amend the 2005 Plan in any manner, but any amendment to increase the maximum aggregate number of shares that may be issued under the 2005 Plan (except by operation of the 2005 Plan s adjustment provision), materially modify the class of individuals eligible to receive awards under the 2005 Plan, or materially increase the benefits to participants under the 2005 Plan requires the approval of our shareholders. No change in any award previously granted under the 2005 Plan may be made which would impair the rights of the holder of such award without the consent of the holder. Our board of directors is prohibited from canceling, reissuing or modifying an award under the 2005 Plan if such action will have the effect of repricing the award.

Adjustments. The maximum numbers of shares of common stock that may be issued under the 2005 Plan, and the number of shares subject to any award that has been granted under the 2005 Plan, are subject to adjustment to reflect stock dividends, stock splits, recapitalizations and similar changes in our capital structure. Under the 2005 Plan, we will not make such adjustments unless they would cause at least a 1% increase or decrease in the number of shares subject to any award available under the 2005 Plan.

2000 Stock Option Plan

General. In October 2000, our board of directors and shareholders adopted and approved the Continental Resources, Inc. 2000 Stock Option Plan (the 2000 Plan). In connection with the adoption of the 2005 Plan, our board of directors terminated the 2000 Plan, except with respect to unexercised options outstanding under the 2000 Plan. The purpose of the 2000 Plan was to provide our directors and employees and employees of our affiliates additional incentives that are designed to motivate them to put forth maximum effort toward the success and growth of the company and to enable us and our affiliates to attract and retain experienced individuals. The 2000 Plan provided for the granting of incentive stock options intended to qualify under Section 422 of the Code and options that do not constitute incentive stock options.

Administration. In February 2006, our board of directors authorized the compensation committee to administer the 2000 Plan for the purposes of awards granted to our employees and employees of our affiliates and consultants. In general, our compensation committee is authorized to select the recipients of options, establish the options terms and conditions, and accelerate such options when to do so would be in the best interest of the company.

Options Granted Under the 2000 Plan. Up to 11,220,000 shares of common stock were originally made available for issuance under the 2000 plan, subject to adjustment as described below. Prior to the termination of the 2000 Plan, options to purchase a total of 2,387,000 shares of common stock were issued. Our board of directors determined the price at which a share of common stock may be purchased upon exercise of an option granted under the 2000 Plan at the time of the grant. In the case of an option that does not constitute an incentive stock option, the exercise price could not be less than 50% of the fair market value of the common stock on the date the option was granted. In the case of an incentive stock option, the exercise price could not be less than 100% of the fair market value of the common stock on the date the option was granted. At the time of the grant of any option or at any time thereafter up until the time of any dividend payment by us, our board of directors could choose to include as part of such award the right to receive dividends or dividend equivalents with respect to such award. The compensation committee has discretion to accelerate the vesting of an option upon the death,

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disability or termination of the grantee s service to the company under special circumstances (as determined by the compensation committee).

Merger, Dissolution, Change of Control, Death of Harold G. Hamm. If we merge, sell substantially all of our assets or dissolve or liquidate and provision is not made in such transaction for the surviving, resulting or acquiring corporation to assume or substitute our outstanding options, such options will automatically vest and become fully exercisable prior to such transaction. If we undergo a change of control (as defined under the 2000 Plan) or Mr. Hamm dies at a time when 35% or more of the total voting power of our voting stock is beneficially owned by Mr. Hamm (individually and as trustee of his revocable inter vivos trust established in April 1984), then all outstanding options will automatically fully vest.

Amendment and Termination of the 2000 Plan and Awards. The maximum term of any award under the 2000 Plan is 10 years. No change in any option previously granted under the 2000 Plan may be made that would be adverse to the holder of such option without the consent of the holder.

Adjustments. The number of shares subject to any award that has been granted under the 2000 Plan is subject to adjustment to reflect stock dividends, stock splits, recapitalizations and similar changes in our capital structure. Under the 2000 Plan, we will not make such adjustments unless they would cause at least a 1% increase or decrease in the number of shares subject to any option granted under the 2000 Plan.

Employment Agreement

We have entered into an employment agreement with Mark E. Monroe, our President and Chief Operating Officer. The agreement provides for a minimum annual salary of $450,000 during each of the years ended October 2, 2006, 2007 and 2008. In the event we terminate the employment without cause or Mr. Monroe resigns for good reason, we will pay him a severance benefit in an amount equal to two times his average salary and bonus and will accelerate the vesting of his restricted stock.

The agreement provides for a long-term incentive bonus payable if Mr. Monroe remains continuously employed by the company through the term of the agreement. The long-term incentive bonus will also be payable if we terminate Mr. Monroe s employment without cause, Mr. Monroe terminates his employment for good reason or his employment is terminated as a result of death or disability. The long-term incentive bonus is determined by multiplying 193,875 by the excess of $30.91 over the fair market value of our common stock as of October 2, 2008 or on the termination date, as applicable.

Events that would allow Mr. Monroe to resign for good reason include (1) the assignment of duties inconsistent with the employee s position and (2) the requirement of the employee to be based at an location outside of the greater Enid, Oklahoma metropolitan area.

On October 3, 2005, we granted Mr. Monroe 193,875 shares of restricted stock, which vest ratably over a three-year period.

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Selling Shareholder and Security Ownership of Certain Beneficial Owners and Management

The following table sets forth certain information regarding the beneficial ownership of our common stock prior to and as of the closing of this offering by:

the selling shareholder and each other person who will beneficially own more than 5% of our common stock then outstanding;

each of our named executive officers;

each of our directors; and

all of our directors and executive officers as a group.

All information with respect to beneficial ownership has been furnished by the respective directors, officers or 5% or more shareholders, as the case may be. The information in the following table gives effect to our 11 for 1 stock split to be effected in the form of a stock dividend concurrent with the consummation of this offering and assumes that the underwriters do not exercise their overallotment option:

	Shares beneficially owned prior to offering				Shares offered hereby	Shares of common stock beneficially owned after offering	
	Voting common stock		Non-voting common stock(1)				
Name of Beneficial Owner	Number	% of class	Number	% of class	Number	Number	%
Harold G. Hamm(2)(3)(4)	7,170,526	90.7%	136,460,082(5)	90.3%			%
Harold Hamm DST Trust(3)	439,406	5.6%	8,348,681	5.5%		8,788,087	%
Harold Hamm HJ Trust(4)	292,974	3.7%	5,566,440	3.7%		5,859,414	%
Mark E. Monroe			193,875(6)	*		193,875(6)	%
Jeffrey B. Hume			385,000(7)	*		385,000(7)	%
Tom E. Luttrell			154,000(8)	*		154,000(8)	%
Jack H. Stark			473,000(9)	*		473,000(9)	%
Robert J. Grant			3,300(10)	*		3,300(10)	%
George S. Littell			3,300(11)	*		3,300(11)	%
Lon McCain			3,300(12)	*		3,300(12)	%
H. R. Sanders, Jr.			3,300(11)	*		3,300(11)	%

All directors and executive officers as a group (11 persons)	7,170,526	90.7%	137,759,820(13)	90.5%	(13)	%

* Less than 1%.

(1) All shares of non-voting common stock will become voting shares of common stock after the consummation of this offering.

(2) Mr. Hamm holds his shares through the Revocable Inter Vivos Trust of Harold G. Hamm, for which Mr. Hamm is both the trustee and sole beneficiary. The address of the Revocable Inter Vivos Trust of Harold G. Hamm is 302 N. Independence, Enid, Oklahoma 73701.

(3) The Harold Hamm DST Trust is a trust established for the benefit of children of Harold G. Hamm. Mr. Hamm is neither the trustee nor the beneficiary of the Harold Hamm DST Trust. Mr. Hamm disclaims beneficial ownership of the shares of our common stock owned by the Harold Hamm DST Trust, and none of these shares are shown as being beneficially owned by Mr. Hamm in the table above. Mr. Bert Mackie is the trustee of the Harold Hamm DST Trust, and his address is c/o Security National Bank, 201 West Broadway, Enid, Oklahoma 73702-1272.

(4) The Harold Hamm HJ Trust is a trust established for the benefit of children of Harold G. Hamm. Mr. Hamm is neither the trustee nor the beneficiary of the Harold Hamm HJ Trust. Mr. Hamm disclaims beneficial ownership of the shares of our common stock owned by the Harold Hamm HJ Trust, and none of these shares are shown as being beneficially owned by Mr. Hamm in the table above. Mr. Bert Mackie is the trustee of the Harold Hamm HJ Trust, and his address is c/o Security National Bank, 201 West Broadway, Enid, Oklahoma 73702-1272.

(5) Includes 146,667 shares of restricted stock which vest 50% on each of October 5, 2007 and October 5, 2008.

(6) Includes 129,250 shares of restricted stock which vest 50% on each of October 3, 2007 and October 3, 2008.

(7) Includes 22,000 shares of restricted stock which vest 50% on each of October 5, 2007 and October 5, 2008, and options to purchase 352,000 shares of our common stock exercisable within 60 days of the date of this prospectus.

(8) Represents shares of non-voting common stock issuable upon the exercise of options to purchase our common stock exercisable within 60 days of the date of this prospectus.

(9) Includes 22,000 shares of restricted stock which vest 50% on each of October 5, 2007 and October 5, 2008, and options to purchase 440,000 shares of our common stock exercisable within 60 days of the date of this prospectus.

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(10) Represents shares of restricted stock granted on January 18, 2006, which vest after a period of one year.

(11) Represents shares of restricted stock granted on January 2, 2006, which vest after a period of one year.

(12) Represents shares of restricted stock granted on February 28, 2006, which vest after a period of one year.

(13) Includes 537,075 shares of restricted stock and options to purchase up to 982,663 shares of our non-voting common stock exercisable within 60 days of the date of this prospectus.

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Certain Relationships and Related Party Transactions

Crude Oil Sales

During the year ended December 31, 2005 and the nine months ended September 30, 2006, we sold approximately 1.3 MMBbls and 1.2 MMBbls of oil from properties located in North Dakota and Montana to Banner for $67.6 million and $61.5 million, respectively. Our principal shareholder and his family trusts owned 100% of the common stock of Banner. Our sales to Banner were based on market prices and considered to be on terms equivalent to arms length transactions. In February 2006, we decided to market the majority of our crude oil in the Rocky Mountain region directly or through a wholly owned subsidiary rather than through an affiliate, and, as Banner has existing contacts and relationships with crude oil purchasers, we decided to purchase Banner. On March 30, 2006, we acquired Banner for approximately $8.8 million, the book value of working capital, principally cash, accounts receivable, crude oil inventory and accounts payable.

During the years ended December 31, 2003, 2004 and 2005, we sold approximately 165 MBbls of oil from properties located in Wyoming to Independent Trading & Transportation Company I, L.L.C. or a subsidiary thereof (ITT) for $3.9 million, 351 MBls for $10.8 million and 263 MBbls for $11.0 million, respectively. Our principal shareholder and his family own 100% of the common stock of ITT. Effective March 2006, we ceased selling oil to ITT. We sold 97 MBbls of oil for $3.7 million during 2006 prior to the cessation of sales to ITT.

We operated crude oil gathering lines in North Dakota and Wyoming on behalf of ITT for which they paid us approximately $185,000, $236,000 and $344,000 during the years ended December 31, 2003, 2004 and 2005, respectively and $782,000 during the nine months ended September 30, 2006. We paid ITT approximately $320,000, $398,000 and $692,000 for crude oil gathering services in North Dakota during the years ended December 31, 2003, 2004 and 2005, respectively. We paid ITT approximately $599,000 during the nine months ended September 30, 2006 for similar services. We believe that our transactions with ITT have been on terms equivalent to arm s-length transactions.

Natural Gas Sales

During the years ended December 31, 2003, 2004 and 2005 and the nine months ended September 30, 2006, we sold approximately 808 MMcf of natural gas for $880,000, 2,394 MMcf for $8.2 million, 4,733 MMcf for $30.3 million and 4,090 MMcf for $22.2 million, respectively, to affiliated natural gas gathering and processing companies owned by our principal shareholder and previous executive officers. Additionally, we paid approximately $707,000, $2.6 million, $10.5 million and $7.1 million for reclaimed oil and residue fuel gas from such companies during the years ended December 31, 2003, 2004 and 2005 and the nine months ended September 30, 2006, respectively. The affiliated natural gas gathering and processing companies were combined into Hiland Partners, LP (Hiland), a publicly traded midstream master limited partnership, in October 2004. Our principal shareholder and his family trusts own the majority of the total outstanding units of Hiland and control its general partner. Our principal shareholder also serves as the Chairman of the Board of Directors of Hiland s general partner. Our sales to and purchases from Hiland are based on market prices and considered to be on terms equivalent to arm s-length transactions. We are generally prohibited, under the terms of an agreement with Hiland, from engaging in the gathering, treating, processing and transportation of natural gas in North America and buying or selling any assets related to the forgoing businesses until February 15, 2010.

On November 8, 2005, we entered into a contract with Hiland for the processing and treatment of gas produced from the CHNU and CHWU. Under the terms of the contract, we agree to deliver low pressure gas to Hiland for compression, treatment and processing at a facility to be constructed by Hiland. Nitrogen and carbon dioxide must be removed from the gas production associated with the increasing oil production from CHNU and CHWU for the gas production to be marketable. Under the terms of the contract, we pay $0.60 per Mcf in gathering and treating fees, and 50% of the electrical costs attributable to compression and plant operation and

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receive 50% of the proceeds from residue gas and plant product sales. After we deliver 36 Bcf of gas, the $0.60 per Mcf gathering and treating fee is eliminated. If the average composite volume of carbon dioxide is less than 10%, we pay an additional $0.10 per Mcf treating fee, otherwise the treating fee is $0.20 per Mcf. We currently plan to invest approximately $6 million during 2006 to construct gas gathering from each well to central tank battery delivery points. The plant is currently expected to be operational during the fourth quarter of 2006. The terms of our contract with Hiland were determined following arm s-length negotiations between our representatives and representatives of Hiland. We believe the terms contained in this agreement are comparable to those we would receive from an unaffiliated third party.

Oilfield Services

During the years ended December 31, 2003, 2004 and 2005 and the nine months ended September 30, 2006, we paid approximately $13.6 million, $14.5 million, $20.4 million and $21.3 million, respectively, to affiliated service companies for oilfield services such as saltwater hauling and workover rigs. A portion of such amount was billed to other interest owners. Prior to October 2004, our principal shareholder owned a majority of the common stock of the affiliated service companies. After such date, the assets of the affiliated service companies were conveyed to Complete Production Services, Inc. (Complete). Our principal shareholder serves on the board of directors of Complete and trusts formed by him currently own approximately 7% of the stock of Complete. We believe that our transactions with the affiliated service companies have been on terms no less favorable to us than we could have achieved with an unaffiliated party.

Pursuant to a strategic customer relationship agreement with Complete, we agree to use commercially reasonable efforts to provide the service companies a first right to provide services or supplies required in our operations so long as such services or supplies can be provided on a timely basis and at competitive market prices. The service companies agree to use commercially reasonable efforts to provide us with requested supplies and services ahead of and before any such supplies and services would otherwise be provided to any other customer who is not then being provided supplies and services pursuant to a binding agreement. The strategic customer relationship agreement can be terminated by either party on or after October 2009.

During the years ended December 31, 2004 and 2005 and the nine months ended September 30, 2006, we paid for costs of approximately $1.2 million, $3.1 million and $3.6 million, respectively, for daywork drilling rig services provided by United Drilling Co. (United). A portion of such amounts was billed to other interest owners. United provided daywork drilling rig services for four wells in 2004, eight wells in 2005 and eight wells through September 30, 2006. Our principal shareholder owns 100% of the common stock of United. We believe that our transactions with United have been on terms no less favorable to us than we could have achieved with an unaffiliated party.

We signed a Compression Services Agreement effective as of January 28, 2005 with Hiland covering the Cedar Hills North and South Medicine Pole Hills Units whereby Hiland agrees to provide to us on a monthly basis the quantities of compressed air and pressurized water that we request. We have agreed to provide, at no cost to Hiland, all fuel, whether gas or electric, and water, in the quantities necessary for Hiland to provide such services. The term of the contract is for four years from the effective date at a cost of approximately $402,000 per month. In 2003 and 2004, we were responsible for operating and maintaining the compression equipment and paid Hiland and a predecessor affiliated gas gathering and processing company $3.8 million in each year for rental of the compression equipment. The annual cost of renting the compression equipment was compared against proposals submitted by third parties and the compression equipment rental terms are considered to be no less favorable than we could have achieved with an unaffiliated party. The incremental annual cost of approximately $1 million being paid under the new contract represented our estimate of the annual wages and overhead associated with our eleven employees that operated the compression equipment and the annual cost of maintaining the compression equipment. Under the new agreement, Hiland is responsible for operating and

maintaining the compression equipment. We did not seek bids from third parties for the operation and maintenance of the compression equipment.

We also signed a Compression Services Agreement effective as of January 28, 2005 with Hiland Partners, GP, LLC (Hiland GP) covering the Medicine Pole Hills Unit and West Medicine Pole Hills Unit whereby Hiland GP agrees to provide compression services. Hiland GP is the general partner of Hiland and our principal shareholder and family trusts own the majority of Hiland GP. We have agreed to provide, at no cost to Hiland GP, all fuel, whether gas or electric, for compression services only, in the quantities necessary for Hiland GP to provide such services. The term is for one year from effective date and automatically renews for additional one-month terms unless terminated by either party upon 15 days notice. During the year ended December 31, 2005 and the nine months ended September 30, 2006, we paid $372,000 and $336,000, respectively, to Hiland GP in reimbursement of actual costs incurred by Hiland GP in providing the services. This contract terminated effective June 28, 2006, and we are now providing those services with our employees. Because amounts paid are the actual costs incurred by Hiland GP for the services provided by them, we believe the terms of this agreement were more favorable than the terms we would have received from an unaffiliated party.

During the years ended December 31, 2003, 2004 and 2005 and the nine months ended September 30, 2006, we paid approximately $669,000, $445,000, $596,000 and $583,000, respectively, for roustabout services to a company owned by a family member of the principal shareholder. During the years ended December 31, 2004 and 2005 and the nine months ended September 30, 2006, we paid approximately $379,000, $222,000 and $472,000, respectively, to Water Tech LLC, a company majority owned by our principal shareholder, for reclaimed oil and contract labor. We believe that our transactions with these affiliated service companies have been on terms no less favorable to us than we could have achieved with an unaffiliated party.

Sales to Shareholders

In July 2004, we sold all of the outstanding stock in our wholly owned subsidiary Continental Gas Inc. (CGI) to our shareholders for $22.6 million. The sales price was representative of the fair value of the net assets based on an appraisal by an independent third party who also provided us with an opinion of the fairness from a financial point of view of the sale of CGI to the shareholders. These assets represented our entire gas gathering, marketing and processing segment.

Commercial Property Transactions

We lease approximately 67,000 square feet of office space from a company owned by our principal shareholder. Rents under these leases totaled approximately $505,000, $506,000, $556,000 and $474,000 during the years ended December 31, 2003, 2004 and 2005 and the nine months ended September 30, 2006, respectively. The current leases covering this space expire at the end of February 2007 and provide for a total annual rent of $646,000. We believe that our office leases are on terms no less favorable to us than we could have achieved with an unaffiliated party. In December 2005, we paid $253,000 to our principal shareholder to acquire an office building and triplex in Baker, Montana, for which we had previously paid $2,300 per month to lease.

Royalty and Common Ownership

Minerals Acquisitions, LLC (Minerals), wholly owned by our principal shareholder and his wife, owns royalty interests in the Cedar Hills North Unit operated by us. During the years ended December 31, 2003, 2004 and 2005 and the nine months ended September 30, 2006, we paid net oil and gas royalties of approximately $40,000, $67,000, $155,000 and $31,000, respectively, to Minerals. Effective December 1, 2005 the royalty interests were transferred to the Revocable InterVivos Trust of Harold G. Hamm. Minerals also owns 100% of

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Jolette Oil (USA) LLC (Jolette), a company formed to acquire undeveloped acreage in the North Dakota Bakken area. In August 2005, we purchased all the assets of Jolette at their book value of $4.5 million. These assets consisted of undeveloped acreage and one producing well in the North Dakota Bakken area.

Wheatland Oil Co. (Wheatland) is owned 75% by our principal shareholder and 25% by another executive officer. Wheatland participates in several of our oil and gas properties with interests generally ranging between 5% and 10% of our interest. During the years ended December 31, 2003, 2004 and 2005 and the nine months ended September 30, 2006, we paid net oil and gas revenues of approximately $0.7 million, $1.7 million, $5.4 million and $5.7 million, respectively, and billed costs of approximately $1.1 million, $1.4 million, $4.2 million and $3.7 million, respectively, to Wheatland.

Registration Rights Agreement

In connection with the closing of this offering, we will enter into a registration rights agreement with our principal shareholder and the two trusts established for the benefit of Mr. Hamm s children pursuant to which we will grant to our principal shareholder and the trusts certain demand and piggyback registration rights.

Under the registration rights agreement, our principal shareholder and the trusts will each have the right to require us to file a registration statement for the public sale of all of the shares of common stock owned by him or it any time after six months following the date the SEC declares the registration statement of which this prospectus forms a part effective. In addition, if we sell any shares of our common stock in a registered underwritten offering, each of our principal shareholder and the trusts will have the right to include his or its shares in that offering. The underwriters of any such offering will have the right to limit the number of shares to be included in such sale.

We will pay all expenses relating to any demand or piggyback registration, except for underwriters or brokers commission or discounts. The securities covered by the registration rights agreement will no longer be registrable under the registration rights agreement if they have been sold to the public either pursuant to a registration statement or under Rule 144 promulgated under the Securities Act.

Shareholder Note

On November 22, 2004, we entered into a subordinated note with our principal shareholder for $50.0 million at an annual rate of 6.00% interest. During the years ended December 31, 2004 and 2005, we paid approximately $308,000 and $2.9 million in interest on the note, respectively. During 2005, our principal shareholder forgave $2.0 million of the principal amount of the note. The outstanding balance was paid by us in full in December 2005.

After the completion of this offering, the ongoing related party transactions described above and any future additional related party transactions will be reviewed by our audit committee on a regular basis.

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Description of Capital Stock

Concurrent with the closing of this offering, Continental Resources, Inc. will amend and restate its certificate of incorporation and bylaws to increase its authorized capital stock, provide for an 11 for 1 stock split in the form of a stock dividend and add certain other provisions as described below. We will effect the stock split concurrent with the closing of this offering. The information in this section describes our amended and restated certificate of incorporation and bylaws that will be in effect following the closing of this offering and assumes that the stock split has taken place.

The following summary of the capital stock and amended and restated certificate of incorporation and bylaws of Continental Resources, Inc. does not purport to be complete and is qualified in its entirety by reference to the provisions of applicable law and to our amended and restated certificate of incorporation and bylaws, forms of which are filed as exhibits to the registration statement of which this prospectus is a part.

The authorized capital stock of Continental Resources, Inc. will consist of 500,000,000 shares of common stock, $.01 par value per share, and 25,000,000 shares of preferred stock, $.01 par value per share.

Common Stock

As of November 9, 2006, we have 7,902,906 shares of voting common stock and 151,185,474 shares of non-voting common stock outstanding. After this offering, we will have 159,088,380 shares of common stock outstanding, all of which will be voting common stock.

Holders of our common stock will be entitled to one vote for each share held on all matters submitted to a vote of shareholders and do not have cumulative voting rights. Accordingly, holders of a majority of the shares of our common stock entitled to vote in any election of directors may elect all of the directors standing for election.

Holders of our common stock are entitled to receive proportionately any dividends if and when such dividends are declared by our board of directors, subject to any preferential dividend rights of outstanding preferred stock. Upon the liquidation, dissolution or winding up of our company, the holders of our common stock are entitled to receive ratably our net assets available after the payment of all debts and other liabilities and subject to the prior rights of any outstanding preferred stock. Holders of our common stock have no preemptive, subscription, redemption or conversion rights. The rights, preferences and privileges of holders of our common stock are subject to, and may be adversely affected by, the rights of the holders of shares of any series of preferred stock that we may designate and issue in the future.

Our common stock has been approved for listing on the NYSE, subject to official notice of issuance, under the symbol CXP.

Preferred Stock

Under the terms of our amended and restated certificate of incorporation, our board of directors will be authorized to designate and issue shares of preferred stock in one or more series without shareholder approval. Our board of directors has discretion to determine the rights, preferences, privileges and restrictions, including voting rights, dividend rights, conversion rights, redemption privileges and liquidation preferences, of each series of preferred stock. It is not possible to state the actual effect of the issuance of any shares of preferred stock upon the rights of holders of the common stock until the board of directors determines the specific rights of the holders of the preferred stock. However, these effects might include:

restricting dividends on the common stock;

diluting the voting power of the common stock;

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impairing the liquidation rights of the common stock; and

delaying or preventing a change in control of our company.

We have no present plans to issue any shares of preferred stock.

Limitations on Liability and Indemnification of Officers and Directors

Our amended and restated certificate of incorporation will provide that none of our directors shall be personally liable to us or our shareholders for monetary damages for breach of fiduciary duty as a director, except liability for:

any breach of the director s duty of loyalty to us or our shareholders;

acts or omissions not in good faith or which involve intentional misconduct or a knowing violation of law;

the payment of unlawful dividends and certain other actions prohibited by the Oklahoma General Corporation Act (the OGCA); and

any transaction from which the director derived any improper personal benefit.

The effect of this provision of our certificate of incorporation will be to eliminate our right and the rights of our shareholders to recover monetary damages against a director for breach of the director s fiduciary duty of care, including breaches resulting from negligent or grossly negligent behavior, except in the situations described above. This provision will not limit or eliminate our rights or the rights of any shareholder to seek non-monetary relief, such as an injunction or rescission in the event of a breach of a director s duty of care.

Our amended and restated bylaws also will provide that we will indemnify officers and directors against losses that they may incur in investigations and legal proceedings resulting from their services to us.

Our amended and restated bylaws also will provide that:

we will be required to indemnify our directors and officers to the fullest extent permitted by Oklahoma law;

- we may indemnify our other employees and agents to the extent that we indemnify our officers and directors, unless otherwise required by law, our certificate of incorporation, our bylaws or agreements to which we are a party; and

- we will be required to advance expenses, as incurred, to our directors and officers in connection with a legal proceeding to the fullest extent permitted by law.

We also have entered into indemnification agreements with each of our current directors and officers to give them additional contractual assurances regarding the scope of the indemnification set forth in our certificate of incorporation and bylaws and to provide additional procedural protections. See Management Indemnification Agreements for a description of such agreements. At present, there is no material pending litigation or proceeding involving any of our directors, officers or employees for which indemnification from us is sought. We are not aware of any threatened litigation that may result in claims for indemnification from us.

We are currently in the process of obtaining liability insurance for our directors and officers that will be effective upon the consummation of this offering.

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Anti-takeover Effects of Provisions of Our Certificate of Incorporation and Bylaws and of Oklahoma Law

Our amended and restated certificate of incorporation and bylaws will contain the following additional provisions, some of which are intended to enhance the likelihood of continuity and stability in the composition of our board of directors and in the policies formulated by our board of directors. In addition, some provisions of the OGCA, if applicable to us, may hinder or delay an attempted takeover without prior approval of our board of directors.

Provisions of our amended and restated certificate of incorporation and bylaws and of the OGCA could discourage attempts to acquire us or remove incumbent management. These provisions could, therefore, prevent shareholders from receiving a premium over the market price for the shares of common stock they hold.

Classified Board. Our amended and restated certificate of incorporation and bylaws will provide that our board of directors be divided into three classes of directors, with the classes to be as nearly equal in number as possible. As a result, approximately one-third of our board of directors will be elected each year. The classification of directors will have the effect of making it more difficult for shareholders to change the composition of our board. Our amended and restated certificate of incorporation and bylaws also will provide that the number of directors will be fixed from time to time exclusively pursuant to a resolution adopted by the board.

Filling Board of Directors Vacancies; Removal. Our amended and restated certificate of incorporation will provide that vacancies and newly created directorships resulting from any increase in the authorized number of directors or any vacancies resulting from death, resignation, retirement, disqualification, removal from office or other cause, may be filled by the affirmative vote of a majority of our directors then in office, though less than a quorum. Each director will hold office until his or her successor is elected and qualified, or until the director s earlier death, resignation, retirement or removal from office. Any director may resign at any time upon written notice to us.

Our amended and restated certificate of incorporation and bylaws will provide that, for so long as Harold G. Hamm, our Chairman, Chief Executive Officer and principal shareholder, and his affiliates own 50% or more of our outstanding shares of common stock, directors may be removed, with or without cause, by the affirmative vote of the holders of a majority of our outstanding shares of common stock. However, from and after the date on which Mr. Hamm and his affiliates cease to own 50% or more of our outstanding shares of common stock, directors may be removed only for cause by affirmative vote of the holders of a majority of our outstanding shares of common stock.

Shareholder Action by Written Consent. Our amended and restated certificate of incorporation will provide that, for so long as Mr. Hamm and his affiliates own 50% or more of our outstanding shares of capital stock entitled to vote in the election of directors, any action required or permitted to be taken by our shareholders may be taken at a duly called meeting of shareholders or by the written consent of shareholders owning the minimum number of shares required to approve the action. However, from and after the date on which Mr. Hamm and his affiliates cease to own 50% or more of our outstanding shares of common stock, shareholders will not be permitted to act by written consent.

Call of Special Meetings. Our amended and restated certificate of incorporation and bylaws will provide that special meetings of our shareholders may be called at any time by the board of directors acting pursuant to a resolution adopted by the board and may not be called by the shareholders.

Advance Notice Requirements for Shareholder Proposals and Director Nominations. Our amended and restated bylaws will provide that shareholders seeking to bring business before or to nominate candidates for

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election as directors at an annual meeting of shareholders must provide timely notice of their proposal in writing to the corporate secretary. With respect to the nomination of directors, to be timely, a shareholder s notice must be delivered to or mailed and received at our principal executive offices (i) with respect to an election of directors to be held at an annual meeting of shareholders, not later than 90 days nor more than 120 days prior to the anniversary date of the proxy statement for the immediately preceding annual meeting of shareholders of the company and (ii) with respect to an election of directors to be held at a special meeting of shareholders, not earlier than 90 days prior to such special meeting and not later than the close of business on the later of the seventieth day prior to such special meeting or the tenth day following the day on which public announcement of the date of the special meeting is first made. With respect to other business to be brought before an annual meeting of shareholders, to be timely, a shareholder s notice must be delivered to or mailed and received at our principal executive offices not later than 90 days nor more than 120 days prior to the anniversary date of the proxy statement for the immediately preceding annual meeting of shareholders of the company. Our amended and restated bylaws also will specify requirements as to the form and content of a shareholder s notice. These provisions may preclude shareholders from bringing matters before an annual meeting of shareholders or from making nominations for directors at an annual meeting of shareholders or may discourage or defer a potential acquirer from conducting a solicitation of proxies to elect its own slate of directors or otherwise attempting to obtain control of us.

No Cumulative Voting. The OGCA provides that shareholders are not entitled to the right to cumulate votes in the election of directors unless our certificate of incorporation provides otherwise. Our amended and restated certificate of incorporation will not expressly provide for cumulative voting. Under cumulative voting, a minority shareholder holding a sufficient percentage of a class of shares may be able to ensure the election of one or more directors.

Authorized but Unissued Shares. Our amended and restated certificate of incorporation will provide that the authorized but unissued shares of common stock and preferred stock are available for future issuance without shareholder approval, subject to various limitations imposed by the New York Stock Exchange. These additional shares may be utilized for a variety of corporate purposes, including future public offerings to raise additional capital, corporate acquisitions and employee benefit plans. The existence of authorized but unissued shares of common stock and preferred stock could make it more difficult or discourage an attempt to obtain control of our company by means of a proxy contest, tender offer, merger or otherwise.

Certificate of Incorporation and Bylaws. Pursuant to the OGCA, our amended and restated certificate of incorporation may not be adopted, repealed or amended, in whole or in part, without the approval of the holders of at least a majority of the outstanding shares of our capital stock. In addition, after such time as Mr. Hamm and his affiliates cease to own 50% or more of our outstanding shares of capital stock entitled to vote in the election of directors, the provision of our certificate of incorporation relating to the classification of our board of directors may not be repealed or amended without the approval of the holders of at least 80% of the outstanding shares of our capital stock entitled to vote in the election of directors.

Our amended and restated certificate of incorporation will permit our board of directors to adopt, amend and repeal our bylaws. Our amended and restated bylaws will provide that our bylaws can be amended by either our board of directors or, as long as Mr. Hamm and his affiliates own 50% or more of our outstanding shares of capital stock entitled to vote in the election of directors, the affirmative vote of the holders of at least a majority of the outstanding shares of our capital stock entitled to vote in the election of directors.

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Oklahoma Business Combination Statute. Under the terms of our amended and restated certificate of incorporation and as permitted under the OCGA, we will elect not to be subject to Section 1090.3 of the OGCA, Oklahoma s anti-takeover law. In general this section prevents an interested shareholder from engaging in a business combination with us for three years following the date the person became an interested shareholder, unless:

- prior to the date the person became an interested shareholder, our board of directors approved the transaction in which the interested shareholder became an interested shareholder or approved the business combination;
- upon consummation of the transaction that resulted in the interested shareholder becoming an interested shareholder, the interested shareholder owns stock having at least 85% of all voting power at the time the transaction commenced, excluding stock held by our directors who are also officers and stock held by certain employee stock plans; or
- on or subsequent to the date of the transaction in which the person became an interested shareholder, the business combination is approved by our board of directors and authorized at a meeting of shareholders by the affirmative vote of the holders of two-thirds of all voting power not attributable to shares owned by the interested shareholder.

An interested shareholder is defined, generally, as any person that owns stock having 15% or more of all of our voting power, any person that is an affiliate or associate of us and owned stock having 15% or more of all of our voting power at any time within the three-year period prior to the time of determination of interested shareholder status, and any affiliate or associate of such person.

A business combination includes:

- any merger or consolidation involving us and an interested shareholder;
- any sale, lease, exchange, mortgage, pledge, transfer or other disposition to or with an interested shareholder of 10% or more of our assets;
- subject to certain exceptions, any transaction that results in the issuance or transfer by us of any of our stock to an interested shareholder;
- any transaction involving us that has the effect of increasing the proportionate share of the stock of any class or series or voting power owned by the interested shareholder;
- the receipt by an interested shareholder of any loans, guarantees, pledges or other financial benefits provided by or through us; or
- any share acquisition by the interested shareholder pursuant to Section 1090.1 of the OGCA.

Because we will opt out of the Oklahoma anti-takeover law, any interested shareholder could pursue a business combination transaction that is not approved by our board of directors.

Oklahoma Control Share Statute. Under the terms of our amended and restated certificate of incorporation and as permitted under the OGCA, we will elect not to be subject to Sections 1145 through 1155 of the OGCA, Oklahoma s control share acquisition statute. In general, Section 1145 of the OGCA defines control shares as our issued and outstanding shares that, in the absence of the Oklahoma control share statute, would have voting power, when added to all of our other shares that are owned, directly or beneficially, by an acquiring person or over which the acquiring person has the ability to exercise voting power, that would entitle the acquiring person, immediately after the acquisition of the shares to exercise, or direct the exercise of, such voting power in the election of directors within any of the following ranges of voting power:

- one-fifth (1/5) or more but less than one-third (1/3) of all voting power;
- one-third (1/3) or more but less than a majority of all voting power; or
- a majority of all voting power.

A control share acquisition means the acquisition by any person of ownership of, or the power to direct the exercise of voting power with respect to, control shares. After a control share acquisition occurs, the acquiring person is subject to limitations on the ability to vote such control shares. Specifically, Section 1149 of the OGCA provides that under most control share acquisition scenarios, the voting power of control shares having voting power of one-fifth (1/5) or more of all voting power is reduced to zero unless the shareholders of the issuing public corporation approve a resolution . . . according the shares the same voting rights as they had before they became control shares. Section 1153 of the OGCA provides the procedures for obtaining shareholder consent of a resolution of an acquiring person to determine the voting rights to be accorded the shares acquired or to be acquired in the control share acquisition.

Because we will opt out of the Oklahoma control share statute, any shareholder holding control shares will have the right to vote his or its shares in full in the election of directors.

Registration Rights

In connection with the closing of this offering, we will enter into a registration rights agreement with our principal shareholder and the two trusts established for the benefit of Mr. Hamm s children covering all of the shares of common stock owned by our principal shareholder and the trusts after the closing of this offering. For a description of the registration rights agreement, see Certain Relationships and Related Party Transactions Registration Rights Agreement.

Transfer Agent and Registrar

The transfer agent and registrar for our common stock is American Stock Transfer & Trust Company.

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Shares Eligible for Future Sale

General

Prior to this offering, there has been no public market for our common stock. Sales of substantial amounts of common stock in the open market, including shares issued upon exercise of outstanding options, or the perception that those sales could occur, could adversely affect prevailing market prices and could impair our ability to raise capital in the future through the sale of our equity securities.

Upon completion of the offering, we will have outstanding 159,088,380 shares of our common stock, and outstanding options to purchase 1,598,666 shares of our common stock. All of the shares sold in the offering, or the shares if the underwriters exercise their overallotment option to purchase additional shares in full, will be freely tradable without restriction under the Securities Act, except for any shares purchased by one of our affiliates, as that term is defined under Rule 144 under the Securities Act. All of the shares outstanding other than the shares sold in this offering (a total of shares, or shares if the underwriters exercise their overallotment option to purchase additional shares in full) will be restricted securities within the meaning of Rule 144 under the Securities Act and may not be sold other than through registration under the Securities Act or pursuant to an exemption from registration, subject to the restrictions on transfer contained in the lock-up agreements described below and in Underwriting.

Persons who may be deemed affiliates generally include individuals or entities that control, are controlled by or are under common control with us and may include our officers, directors and significant shareholders.

Lock-up Agreements

In connection with this offering, we, Harold G. Hamm, the Harold Hamm DST Trust and the Harold Hamm HJ Trust have agreed that, during the period beginning from the date of this prospectus and continuing to and including the date 180 days after the date of this prospectus, neither we nor any of them will, directly or indirectly, offer, sell, offer to sell, contract to sell or otherwise dispose of any shares of our common stock without the prior written consent of J.P. Morgan Securities Inc. and Merrill Lynch, Pierce, Fenner & Smith Incorporated, with limited exceptions as described under Underwriting. We have been informed by J.P. Morgan Securities Inc. and Merrill Lynch, Pierce, Fenner & Smith Incorporated that they have no present intention to consent to the release of the lock-up restrictions described above. This lock-up will not apply to approximately 2,408,937 unvested shares of restricted stock that are currently held by our employees and directors or issuable upon the exercise of options outstanding under our long-term incentive plan, up to an additional 1,100,000 shares covered by grants that we are permitted to award under our existing long-term incentive plan during the 180-day lock-up period and any shares of common stock purchased by our directors, officers, employees and other persons pursuant to the directed share program. We have directed the underwriters to reserve up to shares of common stock for sale to such persons at the initial public offering price through the directed share program. See Underwriting for a description of these lock-up arrangements. Upon the expiration of these lock-up agreements, shares, or shares if the underwriters exercise their overallotment option to purchase additional shares in full, will be eligible for sale in the public market under Rule 144 of the Securities Act, subject to volume limitations and other restrictions contained in Rule 144.

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Rule 144

In general, under Rule 144 as currently in effect, beginning 90 days after the date of this prospectus, a person, or persons whose shares are aggregated, who has beneficially owned restricted shares for at least one year, including the holding period of any prior owner (other than an affiliate of ours) would be entitled to sell within any three-month period a number of shares that does not exceed the greater of:

- 1% of the number of shares of common stock then outstanding; or

- the average weekly reported trading volume of the common stock on the NYSE during the four calendar weeks preceding the filing of a Form 144 with respect to the sale.

Sales under Rule 144 also are subject to manner of sale provisions and notice requirements and to the availability of current public information about us.

Rule 144(k)

Under Rule 144(k), a person who is not deemed to have been an affiliate of ours at any time during the three months preceding a sale and who has beneficially owned the shares proposed to be sold for at least two years, including the holding period of any prior owner (other than an affiliate of ours) is entitled to sell those shares without complying with the manner of sale, public information, volume limitation or notice provisions of Rule 144.

Registration Rights

In connection with the closing of this offering, we will enter into a registration rights agreement with our principal shareholder and the two trusts established for the benefit of Mr. Hamm s children covering all of the shares of common stock owned by our principal shareholder and the trusts after the closing of this offering. For a description of the registration rights agreement, see Certain Relationships and Related Party Transactions Registration Rights Agreement.

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Material U.S. Federal Tax Consequences

for Non-U.S. Holders of Our Common Stock

The following is a general discussion of the material U.S. federal income and estate tax consequences to non-U.S. Holders with respect to the acquisition, ownership and disposition of our common stock. In general, a Non-U.S. Holder for purposes of this discussion is any beneficial owner of our common stock other than the following:

- an individual citizen or resident of the U.S., including an alien individual who is a lawful permanent resident of the U.S. or meets the substantial presence test under section 7701(b)(3) of the Internal Revenue Code of 1986, as amended (the Code);
- a corporation (or an entity treated as a corporation) created or organized in the U.S. or under the laws of the U.S., any state thereof, or the District of Columbia;
- a partnership (or an entity treated as a partnership);
- an estate, the income of which is subject to U.S. federal income tax regardless of its source; or
- a trust, if a U.S. court can exercise primary supervision over the administration of the trust and one or more U.S. persons can control all substantial decisions of the trust, or certain other trusts that have a valid election to be treated as a U.S. person pursuant to the applicable Treasury Regulations.

This discussion is based on current provisions of the Code, final, temporary and proposed Treasury Regulations, judicial opinions, published positions of the Internal Revenue Service, or IRS, and all other applicable administrative and judicial authorities, all of which are subject to change, possibly with retroactive effect. This discussion does not address all aspects of U.S. federal income and estate taxation or any aspects of state, local, or non-U.S. taxation, nor does it consider any specific facts or circumstances that may apply to particular Non-U.S. Holders that may be subject to special treatment under the U.S. federal income tax laws including, but not limited to, insurance companies, real estate investment trusts, regulated investment companies, persons holding our common stock as part of a hedging or conversion transaction or a straddle or other risk-reduction transaction, tax-exempt organizations, pass-through entities, banks or financial institutions, brokers, dealers in securities, and U.S. expatriates. If a partnership or other entity treated as a partnership for U.S. federal income tax purposes is a beneficial owner of our common stock, the tax treatment of a partner in the partnership will generally depend upon the status of the partner and the activities of the partnership. This discussion assumes that the Non-U.S. Holder will hold our common stock as a capital asset, which generally is property held for investment.

Prospective investors are urged to consult their tax advisors regarding the U.S. federal, state and local, and non-U.S. income and other tax considerations of acquiring, holding and disposing of shares of common stock.

Dividends

In general, dividends paid to a Non-U.S. Holder (to the extent paid out of our current or accumulated earnings and profits, as determined under U.S. federal income tax principles) will be subject to U.S. withholding tax at a rate equal to 30% of the gross amount of the dividend, or a lower rate prescribed by an applicable income tax treaty, unless the dividends are effectively connected with a trade or business carried on by the Non-U.S. Holder within the U.S. Under applicable Treasury regulations, a Non-U.S. Holder will be required to satisfy certain certification requirements, generally on IRS Form W-8BEN, or any successor form, directly or through an intermediary, in order to claim a reduced rate of withholding under an applicable income tax treaty. If tax is withheld in an amount in excess of the amount applicable under an income tax treaty, a refund of the excess amount may generally be obtained by filing an appropriate claim for refund with the IRS.

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Dividends that are effectively connected with a U.S. trade or business (and, where an income tax treaty applies, are attributable to a U.S. permanent establishment of the Non-U.S. Holder) generally will not be subject to U.S. withholding tax if the Non-U.S. Holder files the properly completed required forms, including IRS Form W-8ECI, or any successor form, with the payor of the dividend, but instead generally will be subject to U.S. federal income tax on a net income basis in the same manner as if the Non-U.S. Holder were a resident of the U.S. A corporate Non-U.S. Holder that receives effectively connected dividends may be subject to an additional branch profits tax at a rate of 30%, or a lower rate prescribed by an applicable income tax treaty, on its effectively connected earnings and profits, subject to adjustments.

Gain on Sale or Other Disposition of Common Stock

In general, a Non-U.S. Holder will not be subject to U.S. federal income tax on any gain realized upon the sale or other taxable disposition of the Non-U.S Holder s shares of common stock unless:

- the gain is effectively connected with a trade or business carried on by the Non-U.S. Holder within the U.S. (and, where an income tax treaty applies, is attributable to a U.S. permanent establishment of the Non-U.S. Holder), in which case the branch profits tax discussed above may also apply if the Non-U.S. Holder is a corporation;

- the Non-U.S. Holder is an individual who holds shares of common stock as capital assets and is present in the U.S. for 183 days or more in the taxable year of disposition and certain other conditions are met; or

- we are or have been a U.S. real property holding corporation for U.S. federal income tax purposes during specified periods.

A Non-U.S. Holder described in the first and third bullet points above will be subject to tax on the net gain derived from the sale under regular graduated U.S. federal income tax rates. A Non-U.S. Holder described in the second bullet point above will be subject to a 30% tax on the gain derived from the sale, which may be offset by U.S. source capital losses.

Because of the oil and natural gas properties and other real property assets we own, we may be a U.S. real property holding corporation. The determination of whether we are a U.S. real property holding corporation is fact specific and depends on the composition of our assets. Generally, a corporation is a U.S. real property holding corporation if the fair market value of its U.S. real property interests, as defined in the Internal Revenue Code and applicable regulations, equals or exceeds 50% of the aggregate fair market value of its worldwide real property interests and its other assets used or held for use in a trade or business. If we are, have been, or become, a U.S. real property holding corporation, and our common stock is regularly traded on an established securities market, a Non-U.S. Holder who (actually or constructively) holds or held (at anytime during the shorter of the five year period preceding the date of dispositions or the holder s holding period) more than five percent of our common stock would be subject to U.S. federal income tax on a disposition of our common stock, but other Non-U.S. Holders generally would not be. If our common stock is not so traded, all Non-U.S. Holders would be subject to U.S. federal income tax on disposition of our common stock.

You are encouraged to consult your own tax advisor regarding our possible status as a U.S. real property holding corporation and its possible consequences in your particular circumstances.

Information Reporting and Backup Withholding

Generally, we must report annually to the IRS the amount of dividends paid, the name and address of the recipient, and the amount, if any, of tax withheld. A similar report is sent to the recipient. These information reporting requirements apply even if withholding was not required because the dividends were effectively

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connected dividends or withholding was reduced by an applicable income tax treaty. Under income tax treaties or other agreements, the IRS may make its reports available to tax authorities in the recipient s country of residence.

Dividends paid to a Non-U.S. Holder that is not an exempt recipient generally will be subject to backup withholding, currently at a rate of 28% of the gross proceeds, unless a Non-U.S. Holder certifies as to its foreign status, which certification may be made on IRS Form W-8BEN.

Proceeds from the disposition of common stock by a Non-U.S. Holder effected by or through a U.S. office of a broker will be subject to information reporting and backup withholding, currently at a rate of 28% of the gross proceeds, unless the Non-U.S. Holder certifies to the payor under penalties of perjury as to, among other things, its address and status as a Non-U.S. Holder or otherwise establishes an exemption. Generally, U.S. information reporting and backup withholding will not apply to a payment of disposition proceeds if the transaction is effected outside the U.S. by or through a non-U.S. office. However, if the broker is, for U.S. federal income tax purposes, a U.S. person, a controlled foreign corporation, a foreign person who derives 50% or more of its gross income for specified periods from the conduct of a U.S. trade or business, specified U.S. branches of foreign banks or insurance companies or a foreign partnership with various connections to the U.S., information reporting, but not backup withholding, will apply unless:

- the broker has documentary evidence in its files that the holder is a Non-U.S Holder and certain other conditions are met; or

- the holder otherwise establishes an exemption.

Backup withholding is not an additional tax. Rather, the amount of tax withheld is applied as a credit to the U.S. federal income tax liability of persons subject to backup withholding. If backup withholding results in an overpayment of U.S. federal income taxes, a refund may be obtained, provided the required documents are timely filed with the IRS.

Estate Tax

Our common stock owned or treated as owned by an individual who is not a citizen or resident of the U.S. (as specifically defined for U.S. federal estate tax purposes) at the time of death will be includible in the individual s gross estate for U.S. federal estate tax purposes, unless an applicable estate tax treaty provides otherwise.

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Underwriting

The selling shareholder is offering the shares of common stock described in this prospectus through a number of underwriters. J.P. Morgan Securities Inc. and Merrill Lynch, Pierce, Fenner & Smith Incorporated are acting as joint book-running managers of the offering and as representatives of the underwriters. We and the selling shareholder have entered into an underwriting agreement with the underwriters. Subject to the terms and conditions of the underwriting agreement, the selling shareholder has agreed to sell to the underwriters, and each underwriter has severally agreed to purchase, at the public offering price less the underwriting discount set forth on the cover page of this prospectus, the number of shares of common stock listed next to its name in the following table:

Name	Number of shares
J.P. Morgan Securities Inc.	
Merrill Lynch, Pierce, Fenner & Smith Incorporated	
Citigroup Global Markets Inc.	
UBS Securities LLC	
Petrie Parkman & Co., Inc.	
Raymond James & Associates, Inc.	
Total	

The underwriters are committed to purchase all the shares of common stock offered by the selling shareholder if they purchase any shares. The underwriting agreement provides that if an underwriter defaults, the purchase commitments of non-defaulting underwriters may be increased or the offering may be terminated. The underwriting agreement also provides that the obligations of the underwriters are subject to certain conditions precedent, including the absence of any material adverse change in our business and the receipt of certain certificates, opinions and letters from us, the selling shareholder, our counsel and our independent auditors.

The underwriters propose to offer the shares of common stock directly to the public at the initial public offering price set forth on the cover page of this prospectus and to certain dealers at that price less a concession not in excess of $ per share. Any such dealers may resell shares to certain other brokers or dealers at a discount of up to $ per share from the initial public offering price. After the initial public offering of the shares, the offering price and other selling terms may be changed by the underwriters. Sales of shares made outside of the United States may be made by affiliates of the underwriters. The representatives have advised us and the selling shareholder that the underwriters do not intend to confirm discretionary sales in excess of 5% of the shares of common stock offered in this offering.

The underwriters have an option to buy up to additional shares of common stock from the selling shareholder to cover sales of shares by the underwriters which exceed the number of shares specified in the table above. The underwriters have 30 days from the date of this prospectus to exercise this overallotment option. If any shares are purchased with this overallotment option, the underwriters will purchase shares in approximately the same proportion as shown in the table above. If any additional shares of common stock are purchased, the underwriters will offer the additional shares on the same terms as those on which the shares are being offered.

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The underwriting fee is equal to the public offering price per share of common stock less the amount paid by the underwriters to the selling shareholder per share of common stock. The underwriting fee is $ per share. The following table shows the per share and total underwriting discount to be paid to the underwriters assuming both no exercise and full exercise of the underwriters overallotment option to purchase additional shares:

	Without overallotment exercise	With full overallotment exercise
Per share	$	$
Total	$	$

We estimate that the total expenses of this offering, including registration, filing and listing fees, printing fees and legal and accounting expenses, but excluding the underwriting discount, will be approximately $1,350,000, all of which will be paid by us.

We have directed the underwriters to reserve up to shares of common stock for sale to our directors, officers, employees and other persons at the initial public offering price through a directed share program. The number of shares of common stock available for sale to the general public in the public offering will be reduced to the extent these persons purchase any reserved shares. Any shares not so purchased will be offered by the underwriters to the general public on the same basis as other shares offered hereby.

A prospectus in electronic format may be made available on the web sites maintained by one or more underwriters, or selling group members, if any, participating in the offering. Other than the prospectus in electronic format, the information on such web sites is not part of this prospectus. The underwriters may agree to allocate a number of shares to underwriters and selling group members for sale to their online brokerage account holders. Internet distributions will be allocated by the representatives to underwriters and selling group members that may make Internet distributions on the same basis as other allocations.

We, Harold G. Hamm, the Harold Hamm DST Trust and the Harold Hamm HJ Trust have agreed that, without the prior written consent of J.P. Morgan Securities Inc. and Merrill Lynch, Pierce, Fenner & Smith Incorporated, neither we nor any of them will, with limited exceptions as described below, during the period ending 180 days after the date of this prospectus,

offer, pledge, announce the intention to sell, grant any option, right or warrant to purchase, or otherwise transfer or dispose of, directly or indirectly, any shares of our common stock (including, without limitation, common stock which may be deemed to be beneficially owned by such directors, officers and shareholders in accordance with the rules and regulations of the SEC and securities which may be issued upon exercise of a stock option or warrant) or any securities convertible into or exercisable or exchangeable for common stock; or

request or demand that we file a registration statement related to the common stock; or

enter into any swap or other agreement that transfers, in whole or in part, any of the economic consequences of ownership of the common stock, whether any such transaction described above is to be settled by delivery of common stock or such other securities, in cash or otherwise. Notwithstanding the foregoing, we will be able to grant awards under our existing long-term incentive plan covering up to 1,100,000 shares of our common stock during the lock-up period. These shares will not be subject to the lock-up restrictions described above.

In the event that (1) during the last 17 days of the 180-day restricted period, we issue an earnings release or material news or a material event relating to our company occurs; or (2) prior to the expiration of the 180-day

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restricted period, we announce that we will release earnings results during the 16-day period beginning on the last day of the 180-day period, the restrictions described above shall continue to apply until the expiration of the 18-day period beginning on the issuance of the earnings release or the occurrence of the material news or material event.

We have been informed by J.P. Morgan Securities Inc. and Merrill Lynch, Pierce, Fenner & Smith Incorporated that they have no present intention to consent to the release of the lock-up restrictions described above.

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

Our common stock has been approved for listing on the New York Stock Exchange, subject to official notice of issuance, under the symbol CXP.

In connection with this offering, the underwriters may engage in stabilizing transactions, which involves making bids for, purchasing and selling shares of common stock in the open market for the purpose of preventing or retarding a decline in the market price of the common stock while this offering is in progress. These stabilizing transactions may include making short sales of the common stock, which involves the sale by the underwriters of a greater number of shares of common stock than they are required to purchase in this offering, and purchasing shares of common stock on the open market to cover positions created by short sales. Short sales may be covered shorts, which are short positions in an amount not greater than the underwriters overallotment option referred to above, or may be naked shorts, which are short positions in excess of that amount. The underwriters may close out any covered short position either by exercising their overallotment option, in whole or in part, or by purchasing shares in the open market. In making this determination, the underwriters will consider, among other things, the price of shares available for purchase in the open market compared to the price at which the underwriters may purchase shares through the overallotment option. A naked short position is more likely to be created if the underwriters are concerned that there may be downward pressure on the price of the common stock in the open market that could adversely affect investors who purchase in this offering. To the extent that the underwriters create a naked short position, they will purchase shares in the open market to cover the position.

The underwriters have advised us that, pursuant to Regulation M under the Securities Exchange Act of 1934, they may also engage in other activities that stabilize, maintain or otherwise affect the price of the common stock, including the imposition of penalty bids. This means that if the representatives of the underwriters purchase common stock in the open market in stabilizing transactions or to cover short sales, the representatives can require the underwriters that sold those shares as part of this offering to repay the underwriting discount received by them.

These activities may have the effect of raising or maintaining the market price of the common stock or preventing or retarding a decline in the market price of the common stock, and, as a result, the price of the common stock may be higher than the price that otherwise might exist in the open market. Neither we nor any of the underwriters make any representation or prediction as to the direction or magnitude of any effect that the transactions described above may have on the price of our common stock. If the underwriters commence these activities, they may discontinue them at any time. The underwriters may carry out these transactions on the New York Stock Exchange, in the over-the-counter market or otherwise.

Prior to this offering, there has been no public market for our common stock. The initial public offering price will be determined by negotiations between the selling shareholder and the representatives of the underwriters. In determining the initial public offering price, the selling shareholder and the representatives of the underwriters expect to consider a number of factors including:

- the information set forth in this prospectus and otherwise available to the representatives;

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- our prospects and the history and prospects for the industry in which we compete;
- an assessment of our management;
- our prospects for future earnings;
- the general condition of the securities markets at the time of this offering; and
- the recent market prices of, and demand for, publicly traded common stock of generally comparable companies.

None of the underwriters, our company or the selling shareholder can assure investors that an active trading market will develop for our shares of common stock, or that the shares will trade in the public market at or above the initial public offering price.

Certain of the underwriters and their affiliates have provided in the past to us and our affiliates and may provide from time to time in the future certain commercial banking, financial advisory, investment banking and other services for us and such affiliates in the ordinary course of their business, for which they have received and may continue to receive customary fees and commissions. In addition, from time to time, certain of the underwriters and their affiliates may effect transactions for their own account or the account of customers, and hold on behalf of themselves or their customers, long or short positions in our debt or equity securities or loans, and may do so in the future.

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Legal Matters

The validity of the shares of common stock offered by this prospectus will be passed upon for us by Crowe & Dunlevy, A Professional Corporation, Oklahoma City, Oklahoma. Certain other legal matters will be passed upon for us by Vinson & Elkins L.L.P., Houston, Texas. Certain legal matters with respect to the offering will be passed upon for the underwriters by Davis Polk & Wardwell, New York, New York. Vinson & Elkins L.L.P. and Davis Polk & Wardwell will rely upon Crowe & Dunlevy, A Professional Corporation as to all matters of Oklahoma law.

Experts

The consolidated financial statements of Continental Resources, Inc. and subsidiaries as of December 31, 2004 and 2005 and for the years then ended, included in this prospectus and elsewhere in the registration statement have been audited by Grant Thornton LLP, independent registered public accountants, as indicated in their reports with respect thereto, and are included herein in reliance upon the authority of said firm as experts in accounting and auditing.

Ernst & Young LLP, independent registered public accounting firm, has audited our consolidated statements of income, shareholders equity, and cash flows for the year ended December 31, 2003, as set forth in their report. We have included such financial statements in the prospectus and elsewhere in the registration statement in reliance on Ernst & Young LLP s report, given on their authority as experts in accounting and auditing.

Estimates of the oil and gas reserves of Continental Resources, Inc. and related future net cash flows and the present values thereof as of December 31, 2003, 2004 and 2005 included herein were based in part upon reserve reports prepared by Ryder Scott Company, L.P., independent petroleum engineers. We have incorporated these estimates in reliance on the authority of such firm as an expert in such matters.

Where You Can Find More Information

We have filed with the SEC under the Securities Act a registration statement on Form S-1 with respect to the common stock offered by this prospectus. This prospectus, which constitutes part of the registration statement, does not contain all the information set forth in the registration statement or the exhibits and schedules which are part of the registration statement, portions of which are omitted as permitted by the rules and regulations of the SEC. Statements made in this prospectus regarding the contents of any contract or other document are summaries of the material terms of the contract or document. With respect to each contract or document filed as an exhibit to the registration statement, reference is made to the corresponding exhibit. For further information pertaining to us and the common stock offered by this prospectus, reference is made to the registration statement, including the exhibits and schedules thereto, copies of which may be inspected without charge at the public reference facilities of the SEC at 100 F. Street, N.E., Washington, D.C. 20549. Copies of all or any portion of the registration statement may be obtained from the SEC at prescribed rates. Information on the public reference facilities may be obtained by calling the SEC at 1-800-SEC-0330. In addition, the SEC maintains a web site that contains reports, proxy and information statements and other information that is filed through the SEC s EDGAR System. The web site can be accessed at http://www.sec.gov.

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Report of Independent Registered Public Accounting Firm

Board of Directors

Continental Resources, Inc.

We have audited the accompanying consolidated balance sheets of Continental Resources, Inc. and Subsidiary as of December 31, 2004 and 2005, and the related consolidated statements of income, shareholders equity and cash flows for the years 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 audits.

We conducted our audits in accordance with standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. The Company is not required to have, nor were we engaged to perform an audit of its internal control over financial reporting. Our audits included consideration of internal control over financial reporting as a basis for designing audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the Company s internal control over financial reporting. Accordingly, we express no such opinion. An audit also includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our 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 Continental Resources, Inc. and Subsidiary as of December 31, 2004 and 2005, and the results of their operations and their cash flows for the years then ended in conformity with accounting principles generally accepted in the United States of America.

/s/ Grant Thornton LLP

Oklahoma City, Oklahoma

March 6, 2006

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Report of Independent Registered Public Accounting Firm

The Board of Directors and Shareholders

Continental Resources, Inc.

We have audited the accompanying consolidated statements of income, shareholders equity, and cash flows of Continental Resources, Inc. and subsidiary for the year ended December 31, 2003. 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.

We conducted our audit in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. We were not engaged to perform an audit of the Company s internal control over financial reporting. Our audit included consideration of internal control over financial reporting as a basis for designing audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the Company s internal control over financial reporting. Accordingly, we express no such opinion. An audit also includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, and evaluating the overall financial statement presentation.

In our opinion, the financial statements of Continental Resources, Inc. and subsidiary referred to above present fairly, in all material respects, the consolidated results of their operations and their cash flows for the year ended December 31, 2003, in conformity with U.S. generally accepted accounting principles.

As discussed in Note 1 to the consolidated financial statements, effective January 1, 2003, the Company adopted Statement of Financial Accounting Standards No. 143, *Accounting for Asset Retirement Obligations.*

/s/ Ernst & Young LLP

Oklahoma City, Oklahoma

March 25, 2004,

except for the first and third paragraphs of Note 12, as to which the date is

March 6, 2006

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Continental Resources, Inc. and Subsidiary

Consolidated Balance Sheets

	Historical			Pro forma
	December 31,		September 30,	September 30,
	2004	2005	2006	2006
			(Unaudited)	
	(In thousands, except par values and share data)			
Assets				
Current assets:				
Cash and cash equivalents	$ 15,894	$ 6,014	$ 4,456	$ 4,456
Receivables:				
Oil and gas sales	21,917	20,509	59,759	59,759
Affiliated parties	8,045	42,112	10,910	10,910
Joint interest and other, net	8,191	14,726	24,544	24,544
Inventories	5,592	4,826	8,325	8,325
Prepaid expenses	1,031	660	149	149
Assets held for sale	6,374			
Total current assets	67,044	88,847	108,143	108,143
Net property and equipment, based on successful efforts method of accounting	434,339	509,393	672,415	672,415
Debt issuance costs, net	3,568	1,994	2,338	2,338
Total assets	$ 504,951	$ 600,234	$ 782,896	$ 782,896
Liabilities and shareholders equity				
Current liabilities:				
Accounts payable trade	$ 21,170	$ 33,598	$ 49,997	$ 49,997
Accounts payable to affiliated parties	3,343	3,121	12,981	12,981
Dividend payable			516	516
Accrued liabilities	12,541	28,795	39,039	39,039
Revenues and royalties payable	12,622	31,655	35,754	35,754
Current portion of long-term debt and capital leases	3,348			
Liabilities related to assets held for sale	1,695			
Current portion of asset retirement obligation	559	2,120	1,795	1,795
Total current liabilities	55,278	99,289	140,082	140,082
Long-term debt, net of current portion	230,019	143,000	160,000	160,000
Due to shareholder	50,000			
Other noncurrent liabilities:				
Capital leases	7,155			
Asset retirement obligation, net of current portion	31,938	32,233	35,374	35,374
Other noncurrent liabilities	176	982	1,158	1,158
Total other noncurrent liabilities	39,269	33,215	36,532	36,532
Commitments and contingencies (Note 10)				
Shareholders equity:				

Preferred stock, $0.01 par value: 1,000,000 shares authorized; no shares issued and outstanding				
Common stock, $.01 par value; 20,000,000 shares authorized, 14,368,919 shares issued and outstanding at December 31, 2004; 14,458,966 shares issued and outstanding at December 31, 2005 and 14,457,314 shares issued and outstanding at September 30, 2006	144	144	144	144
Additional paid-in-capital	25,087	27,087	27,087	380,919
Retained earnings	105,154	297,461	418,972	65,140
Accumulated other comprehensive income		38	79	79
Total shareholders equity	130,385	324,730	446,282	446,282
Total liabilities and shareholders equity	$ 504,951	$ 600,234	$ 782,896	$ 782,896

See Note 1 relating to pro forma information.

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

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Continental Resources, Inc. and Subsidiary

Consolidated Statements of Income

	Year ended December 31,			Nine months ended September 30,	
	2003	2004	2005	2005	2006
				(Unaudited)	
Revenues:	(In thousands, except share data)				
Oil and natural gas sales	$ 134,196	$ 162,419	$ 252,947	$ 224,835	$ 270,641
Oil and natural gas sales to affiliates	4,752	19,016	108,886	26,768	87,363
Crude oil marketing and trading	169,547	226,664			
Oil and natural gas service operations	9,114	10,811	13,931	10,447	11,735
Total revenues	317,609	418,910	375,764	262,050	369,739
Operating costs and expenses:					
Production expense	32,716	36,801	39,709	27,768	33,487
Production expense to affiliates	8,105	6,953	13,045	10,488	12,673
Production tax	10,251	12,297	16,031	10,930	16,610
Exploration expense	17,221	12,633	5,231	2,493	9,085
Crude oil marketing and trading	166,731	227,210			
Oil and gas service operations	5,641	6,466	7,977	5,663	6,644
Depreciation, depletion, amortization and accretion	40,256	38,627	49,802	34,584	46,376
Property impairments	8,975	11,747	6,930	5,760	9,080
General and administrative	9,604	12,400	31,266	24,847	19,814
(Gain) loss on sale of assets	(589)	150	(3,026)	(2,906)	(292)
Total operating costs and expenses	298,911	365,284	166,965	119,627	153,477
Income from operations	18,698	53,626	208,799	142,423	216,262
Other income (expense):					
Interest expense	(19,251)	(23,309)	(11,326)	(11,109)	(8,522)
Interest expense to affiliates	(510)	(308)	(2,894)		
Loss on redemption of bonds		(4,083)			
Other	295	890	867	498	1,230
	(19,466)	(26,810)	(13,353)	(10,611)	(7,292)
Income (loss) from continuing operations before income taxes	(768)	26,816	195,446	131,812	208,970
Provision (benefit) for income taxes			1,139	1,139	(132)
Income (loss) from continuing operations	(768)	26,816	194,307	130,673	209,102
Discontinued operations	946	1,680			
Loss on sale of discontinued operations		(632)			
Income before cumulative effect of change in accounting principle	178	27,864	194,307	130,673	209,102
Cumulative effect of change in accounting principle	2,162				

Net income	$ 2,340	$ 27,864	$ 194,307	$ 130,673	$ 209,102
Basic:					
Income from continuing operations per share	$ (0.05)	$ 1.87	$ 13.52	$ 9.09	$ 14.55
Net income per share	0.16	1.94	13.52	9.09	14.55
Diluted:					
Income from continuing operations per share	(0.05)	1.85	13.42	9.00	14.40
Net income per share	0.16	1.93	13.42	9.00	14.40
Cash dividends per share		1.04	0.14	0.14	6.06
Pro forma C-corporation and stock split data: (unaudited)					
Income (loss) from continuing operations before income taxes	$ (768)	$ 26,816	$ 195,446	$ 131,812	$ 208,970
Pro forma provision (benefit) for income taxes attributable to operations	(292)	10,190	74,269	50,089	79,409
Pro forma income (loss) from continuing operations after tax	(476)	16,626	121,177	81,723	129,561
Discontinued operations net of tax	587	1,042			
Loss on sale of discontinued operations		(392)			
Cumulative effect of change in accounting principle net of tax	1,340				
Pro forma net income	$ 1,451	$ 17,276	$ 121,177	$ 81,723	$ 129,561
Pro forma basic earnings per share	$ 0.01	$ 0.11	$ 0.77	$ 0.52	$ 0.82
Pro forma diluted earnings per share	0.01	0.11	0.76	0.51	0.81

See Note 1 relating to pro forma information.

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

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Continental Resources, Inc. and Subsidiary

Consolidated Statements of Shareholders Equity

	Shares outstanding	Common stock	Additional paid-in capital	Retained earnings	Accumulated other comprehensive income	Total shareholders equity
	(In thousands, except share data)					
Balance, December 31, 2002	14,368,919	$ 144	$ 25,087	$ 89,850	$	$ 115,081
Comprehensive income:						
Net income				2,340		2,340
Change in fair value of derivative contracts					(489)	(489)
Total comprehensive income						1,851
Balance, December 31, 2003	14,368,919	144	25,087	92,190	(489)	116,932
Comprehensive income:						
Net income				27,864		27,864
Change in fair value of derivative contracts					(5,907)	(5,907)
Reclassification of loss on settled contracts					6,396	6,396
Net change in fair value of derivative contracts						489
Total comprehensive income						28,353
Cash dividends				(14,900)		(14,900)
Balance, December 31, 2004	14,368,919	144	25,087	105,154		130,385
Comprehensive income:						
Net income				194,307		194,307
Other comprehensive income					38	38
Total comprehensive income						194,345
Issuance of restricted stock	90,047					
Capital contribution			2,000			2,000
Cash dividends				(2,000)		(2,000)
Balance, December 31, 2005	14,458,966	144	27,087	297,461	38	324,730
Comprehensive income (unaudited):						
Net income (unaudited)				209,102		209,102
Other comprehensive income (unaudited)					41	41
Total comprehensive income (unaudited)						209,143
Issuance of restricted stock (unaudited)	5,550					
Forfeited restricted stock (unaudited)	(7,202)					
Cash dividends (unaudited)				(87,591)		(87,591)
Balance, September 30, 2006 (unaudited)	14,457,314	$ 144	$ 27,087	$ 418,972	$ 79	$ 446,282

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

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Continental Resources, Inc. and Subsidiary

Consolidated Statements of Cash Flows

	Year ended December 31,			Nine months ended September 30,	
	2003	2004	2005	2005	2006
				(Unaudited)	
			(In thousands)		
Cash flows from operating activities:					
Net income	$ 2,340	$ 27,864	$ 194,307	$ 130,673	$ 209,102
Adjustments to reconcile net income to net cash provided by operating activities:					
Depreciation, depletion and amortization	42,473	38,987	48,206	33,390	45,172
Accretion of asset retirement obligation	1,151	1,036	1,596	1,194	1,248
Impairment of properties	8,975	11,747	6,930	5,760	9,080
Change in derivative fair value	(1,455)				
Amortization of debt issuance costs	1,633	4,789	1,662	1,246	744
(Gain) loss on sale of assets	(239)	1,566	(3,026)	(2,906)	(292)
Loss on redemption of bonds		4,083			
Cumulative effect of change in accounting principle	(2,162)				
Dry hole costs	13,566	9,489	1,432	126	5,142
Equity compensation	197	2,010	13,715	12,332	4,976
Changes in assets and liabilities:					
Accounts receivable	(9,972)	(15,133)	(39,194)	(43,829)	(17,866)
Inventories	1,341	(280)	766	(489)	(3,499)
Prepaid expenses	115	(695)	371	856	511
Accounts payable	1,285	7,129	12,205	4,654	26,259
Revenues and royalties payable	2,951	4,372	19,033	14,953	4,099
Accrued liabilities and other	3,007	(2,901)	6,456	3,669	4,147
Other noncurrent assets		(221)			
Other noncurrent liabilities	40	12	806	345	176
Net cash provided by operating activities	65,246	93,854	265,265	161,974	288,999
Cash flows from investing activities:					
Exploration and development	(95,880)	(88,361)	(140,591)	(91,781)	(209,587)
Purchase of other property and equipment	(18,085)	(5,190)	(1,942)	(779)	(5,196)
Purchase of oil and gas properties	(180)	(756)	(2,267)	(1,619)	(6,505)
Proceeds from sale of assets	5,354	389	11,084	10,884	1,852
Net cash acquired on disposition of subsidiary		20,926			
Net cash used in investing activities	(108,791)	(72,992)	(133,716)	(83,295)	(219,436)
Cash flows from financing activities:					
Line of credit borrowings and other	49,405	147,100	25,000		216,000
Repayment of senior subordinated notes		(131,233)			
Repayment of shareholder note			(48,000)		

Repayment of line of credit and other	(5,590)	(4,562)	(112,464)	(82,464)	(199,000)
Payment of stock-based compensation			(3,915)	(1,134)	
Dividends to shareholders		(14,900)	(2,000)	(2,000)	(87,075)
Debt issuance costs	(513)	(3,650)	(88)	(88)	(1,087)
Net cash provided by (used in) financing activities	43,302	(7,245)	(141,467)	(85,686)	(71,162)
Effect of exchange rate changes on cash and cash equivalents			38	40	41
Net change in cash and cash equivalents	(243)	13,617	(9,880)	(6,967)	(1,558)
Cash and cash equivalents at beginning of period	2,520	2,277	15,894	15,894	6,014
Cash and cash equivalents at end of period	$ 2,277	$ 15,894	$ 6,014	$ 8,927	$ 4,456

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

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Continental Resources, Inc. and Subsidiary

Notes to Consolidated Financial Statements (continued)

(Information as of September 30, 2006 and for the nine months ended September 30, 2005 and 2006 are unaudited)

1. Organization and Summary of Significant Accounting Policies

Description of Company

Continental Resources, Inc. (Continental or the Company) was incorporated in Oklahoma on November 16, 1967, as Shelly Dean Oil Company. On September 23, 1976, the name was changed to Hamm Production Company. In January 1987, the Company acquired all of the assets and assumed the debt of Continental Trend Resources, Inc. and affiliated entities J.S. Aviation and Wheatland Oil Co. were merged into Hamm Production Company, and the corporate name was changed to Continental Trend Resources, Inc. In 1991, the Company s name was changed to Continental Resources, Inc. Effective June 1, 1997, the Company converted to an S-corporation under subchapter S of the Internal Revenue Code.

On July 21, 2004, the Company completed the sale of all of the outstanding stock of its subsidiary Continental Gas, Inc. (CGI) to the Company s shareholders, for $22.6 million in cash. The sales price was representative of the fair value of the net assets based on an appraisal by an independent third party who also provided the Company with an opinion of the fairness from a financial point of view of the sale of CGI to the shareholders. The CGI assets included seven gas gathering systems and three gas-processing plants. (Note 12) Discontinued operations in the consolidated financial statements represent the operations of CGI. (Note 12)

Continental had one wholly owned subsidiary, Continental Resources of Illinois, Inc. (CRII) at December 31, 2005. CRII was incorporated in June 2001 for the purpose of acquiring the assets of Farrar Oil Company and Har-Ken Oil Company. Continental acquired Banner Pipeline Company, L.L.C. (Banner) on March 30, 2006 (Note 15). CRII and Banner were Continental s only subsidiaries at September 30, 2006. CRII was merged into Continental on October 12, 2006.

Continental s principal business is oil and natural gas exploration, development and production. As of December 31, 2005, the Company had interests in approximately 1,434 wells and serves as the operator of 1,213 of these wells. The Company s operations are primarily in the Rocky Mountain, the Mid-Continent and the Gulf Coast regions of the United States.

Basis of presentation

All significant inter-company accounts and transactions have been eliminated in the consolidated financial statements. Certain reclassifications have been made to prior year amounts to conform to current year presentation.

The preparation of financial statements in conformity with accounting principles generally accepted in the United States of America requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities, the disclosure of contingent assets and liabilities at the date of the financial statements, and the reported amounts of revenues and expenses during the reporting period. Actual results could differ from those estimates. Of the estimates and assumptions that affect reported results, the estimate of the Company s oil and natural gas reserves, which is used to compute depreciation, depletion, amortization and impairment on producing oil and gas properties, is the most significant.

Unaudited Interim Financial Statements

The accompanying unaudited consolidated financial statements as of September 30, 2006 and for the nine months ended September 30, 2005 and 2006 have been prepared in accordance with accounting principles

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Continental Resources, Inc. and Subsidiary

Notes to Consolidated Financial Statements (continued)

(Information as of September 30, 2006 and for the nine months ended September 30, 2005 and 2006 are unaudited)

generally accepted in the United States for interim financial information and Article 10 of Regulation S-X. Accordingly, they do not include all of the information and footnotes required by accounting principles generally accepted in the United States for complete financial statements. In the opinion of management, all material adjustments (consisting only of normal and recurring adjustments) necessary to present a fair statement of our financial position and results of operations for the interim periods included herein have been made, and the disclosures contained herein are adequate to make the information presented not misleading. Operating results for the nine months ended September 30, 2006 are not necessarily indicative of the results that may be expected for the year ended December 31, 2006.

Revenue recognition

Oil and natural gas sales result from undivided interests held by the Company in oil and natural gas properties. Sales of oil and natural gas produced from oil and natural gas operations are recognized when the product is delivered to the purchaser and title transfers to the purchaser. The Company uses the sales method of accounting for natural gas imbalances in those circumstances where it has under-produced or over-produced its ownership percentage in a property. Under this method, a receivable or liability is recognized only to the extent that an imbalance cannot be recouped from the reserves in the underlying properties. The Company s aggregate imbalance positions at December 31, 2004 and 2005 were not material. Charges for gathering and transportation are included in production expenses.

During 2004 and the first three months of 2005, we purchased barrels of oil back from certain of our wellhead purchasers downstream of the initial sales point to exchange at the Cushing, Oklahoma hub in order to minimize pricing differentials with the NYMEX oil futures contract. In 2005, revenues of $39.8 million and expenses of $39.7 million pertaining to these marketing activities were netted as provided by Emerging Issues Task Force (EITF) 04-13, which we adopted as of January 2005. We presented this purchase and sale activity gross in the 2003 and 2004 income statement as crude oil marketing and trading revenues of $169.5 million and $226.7 million and crude oil marketing and trading expenses of $166.7 million and $227.2 million under the guidance provided by EITF 99-19, Reporting Revenues Gross as a Principal and/or Net as an Agent. We ceased marketing our production in this manner in March 2005 and now generally market our production at the wellhead.

Cash and cash equivalents

The Company considers all highly liquid investments with original maturities of three months or less to be cash equivalents. The Company maintains its cash and cash equivalents in accounts that may not be federally insured. The Company has not experienced any losses in such accounts and believes it is not exposed to any significant credit risk.

At December 31, 2004 and 2005, the Company s cash included approximately $481,000 and $301,000, respectively, in a Canadian bank, which was converted to US dollars using the exchange rates in effect at December 31, 2004 and 2005.

Accounts receivable

The Company operates exclusively in oil and natural gas exploration and production related activities. Oil and natural gas sales and joint interest receivables are generally unsecured. Accounts receivable are due within

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Continental Resources, Inc. and Subsidiary

Notes to Consolidated Financial Statements (continued)

(Information as of September 30, 2006 and for the nine months ended September 30, 2005 and 2006 are unaudited)

30 days and considered delinquent after 60 days. The Company determines its allowance for doubtful accounts by considering a number of factors, including the length of time accounts are past due, the Company s loss history, and the customer or working interest owner s ability to pay. The Company writes off specific accounts when they become uncollectible and any payments subsequently received on these receivables are credited to the allowance for doubtful accounts. The following table presents the allowance for doubtful accounts at December 31, 2003, 2004 and 2005 and changes in the allowance for these years:

	Balance at beginning of period	Additions charged to costs and expenses	Deductions	Balance at end of period
Year ended December 31, 2003	$ 544,417	$	$ (314,445)	$ 229,972
Year ended December 31, 2004	229,972	23,000		252,972
Year ended December 31, 2005	252,972	59,378	(140,899)	171,451

Concentration of credit risk

We are subject to credit risk due to concentration of our crude oil and natural gas receivables with several significant customers. The three largest purchasers of the Company s oil and gas production accounted for 53%, 56% and 60% of total oil and natural gas sales revenues for 2003, 2004 and 2005, respectively. These purchasers constituted all purchasers with oil and natural gas sales in excess of 10% of total oil and natural gas sales. The Company does not require collateral. While the Company believes its recorded receivables will be collected, in the event of default the Company would follow normal collection procedures. The Company does not believe the loss of any single purchaser would materially impact its operating results, as oil and natural gas are fungible products with well-established markets and numerous purchasers.

Debt issuance costs

Costs incurred in connection with the issuance of long-term debt are capitalized and amortized over the term of the related debt. The Company had capitalized costs of $3.6 million and $2.0 million relating to the issuance of our long-term debt at December 31, 2004 and 2005, respectively. During the three years ended December 31, 2005, the Company recognized associated amortization expense of $1.6 million, $4.8 million and $1.7 million, respectively.

Inventories

Inventories are stated at the lower of average cost or market. Inventory consists primarily of tubular goods and production equipment, which totaled approximately $3.4 million and $4.8 million at December 31, 2004 and 2005, respectively, and $4.6 million at September 30, 2006 and crude oil of approximately $2.2 million at December 31, 2004 and $3.7 million at September 30, 2006.

Property and equipment

Property and equipment are capitalized and stated at cost, while maintenance and repairs are expensed as incurred.

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Continental Resources, Inc. and Subsidiary

Notes to Consolidated Financial Statements (continued)

(Information as of September 30, 2006 and for the nine months ended September 30, 2005 and 2006 are unaudited)

Depreciation and amortization are provided in amounts sufficient to expense the cost of depreciable assets to operations over their estimated useful lives using the straight-line method. Estimated useful lives are as follows:

Property and Equipment	Useful Lives in Years
Furniture and fixtures	10
Automobiles	5
Machinery and equipment	10-20
Office and computer equipment	5
Building and improvements	10-40

Oil and gas properties

The Company uses the successful efforts method of accounting for oil and gas properties whereby costs to acquire mineral interests in oil and gas properties, drill and equip exploratory wells that find proved reserves and to drill and equip development wells are capitalized. Geological and geophysical costs, seismic costs, lease rentals and costs associated with unsuccessful exploratory wells are expensed as incurred. Maintenance and repairs are expensed as incurred, except that the cost of replacements or renewals that expand capacity or improve production are capitalized. As of December 31, 2004 and 2005, property and equipment included $21.1 million and $21.9 million, respectively, of asset retirement costs.

The Company reports capitalized exploratory drilling costs on the balance sheet according to Statement of Financial Accounting Standards (SFAS) No. 19, Financial Accounting and Reporting by Oil and Gas Producing Companies (SFAS No. 19). On a monthly basis, the Company capitalizes the costs of drilling exploratory wells pending determination of whether the well has found proved reserves. The Company capitalizes costs associated with the acquisition or construction of support equipment and facilities with the drilling and development costs to which they relate. If the well has proved reserves, the capitalized costs become part of well equipment and facilities; however, if proved reserves are not found, the capitalized costs associated with the well are expensed, net of any salvage value. Total capitalized exploratory drilling costs, as of December 31, 2004 and 2005, pending the determination of proved reserves were $3.2 million and $1.9 million, respectively. None of these costs were suspended beyond one year.

Production expenses are those costs incurred by the Company to operate and maintain its oil and natural gas properties and associated equipment and facilities. Production expenses include labor costs to operate the Company s properties, repairs and maintenance, and materials and supplies utilized in the Company s operations.

In 2001, the Financial Accounting Standards Board (FASB) issued SFAS No. 143, Accounting for Asset Retirement Obligations (SFAS No. 143) which requires entities to record the fair value of a liability for an asset retirement obligation in the period in which it is incurred and a corresponding increase in the carrying amount of the related long-lived asset. Subsequently, the asset retirement costs are charged to expense using a systematic and rational method and the liability is accreted to the expected abandonment amount over the asset s life. The Company adopted SFAS No. 143 on January 1, 2003 and recorded a $2.2 million cumulative effect adjustment associated with the adoption. The adoption of SFAS No. 143 resulted in a net increase to Property and Equipment and Asset Retirement Obligations of approximately $27.8 million and $25.6 million, respectively.

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Continental Resources, Inc. and Subsidiary

Notes to Consolidated Financial Statements (continued)

(Information as of September 30, 2006 and for the nine months ended September 30, 2005 and 2006 are unaudited)

The Company s primary asset retirement obligations relate to future plugging and abandonment expenses on its oil and natural gas properties and related facilities disposal. The following table summarizes the changes in the Company s future abandonment liability from January 1, 2004 through December 31, 2005 (in thousands):

	2004	2005
Asset Retirement Obligation liability at January 1,	$ 26,608	$ 34,192
Asset Retirement Obligation accretion expense	1,036	1,596
Plus: Revisions	6,726	
Additions for new assets	516	1,031
Less: Plugging costs and sold assets	(694)	(2,466)
Asset Retirement Obligation liability at December 31,	$ 34,192	$ 34,353

The 2004 asset retirement obligation includes approximately $1.7 million, which is included in current liabilities related to assets held for sale. These related properties were sold in 2005 and are reflected as held for sale at December 31, 2004.

The Company considered the impact of FASB Interpretation No. 47, Accounting for Conditional Asset Retirement Obligations and determined that it did not have a material effect on the Company s results of operations or financial condition.

Depreciation, depletion, amortization, accretion and impairment

Depreciation, depletion, and amortization (DD&A) of capitalized drilling and development costs, including related support equipment and facilities, of producing oil and gas properties are computed using the units of production method on an individual property, field or unit basis based on total estimated proved developed oil and gas reserves. Amortization of producing leasehold is based on the unit-of-production method using total estimated proved reserves. In arriving at rates under the unit-of-production method, the quantities of recoverable oil and natural gas are established based on estimates made by the Company s geologists, engineers and independent reserve engineers. Upon sale or retirement of properties, the cost and related accumulated DD&A are eliminated from the accounts and the resulting gain or loss is recognized. Unit of production rates are revised whenever there is an indication of a need, but at least twice annually in conjunction with our semi-annual and annual reserve reports. Revisions are accounted for prospectively as changes in accounting estimates.

Non-producing properties consist of undeveloped leasehold costs and costs associated with the purchase of certain proved undeveloped reserves. Individually significant non-producing properties are periodically assessed for impairment of value and a loss is recognized at the time of impairment by providing an impairment allowance. Other non-producing properties are amortized on a composite method based on the Company s estimated experience of successful drilling and the average holding period. Impairment of non-producing properties was $5.2 million, $5.5 million, and $4.4 million for 2003, 2004, and 2005 and $3.5 million and $3.7 million for the nine months ended September 30, 2005 and 2006, respectively.

In accordance with the provisions of SFAS No. 144, Accounting for the Impairment or Disposal of Long-Lived Assets , the Company recognizes impairment expenses for developed oil and gas properties and other long-lived assets when indicators of impairment are present and the undiscounted cash flows from proved and risk adjusted probable reserves are not sufficient to recover the assets carrying amount. The impairment loss is measured by comparing the fair value of the asset to its carrying amount. Fair values are based on discounted future cash flows. The Company s oil and gas properties are reviewed for indicators of impairment on a

Continental Resources, Inc. and Subsidiary

Notes to Consolidated Financial Statements (continued)

(Information as of September 30, 2006 and for the nine months ended September 30, 2005 and 2006 are unaudited)

field-by-field basis, resulting in the recognition of impairment provisions of $3.8 million, $6.2 million, and $2.5 million respectively, for 2003, 2004 and 2005 and $2.2 million and $5.3 million, respectively, for the nine months ended September 30, 2005 and 2006. The majority of the impairment recognized in these years relates to fields comprised of a small number of properties or single wells on which the Company does not expect sufficient future net cash flows to recover its carrying cost.

The costs of retired, sold, or abandoned properties that constitute part of an amortization base are charged or credited, net of proceeds received, to the accumulated depletion, depreciation, and amortization reserve. Gains or losses from the disposal of other properties are recognized in the current period. Effective July 1, 2005, the Company adopted SFAS No. 153, Exchanges of Nonmonetary Assets, an Amendment of APB Opinion No. 29 (SFAS No. 153), for the exchanges of nonmonetary assets occurring after the implementation date. Prior to implementing SFAS No. 153, the Company generally did not recognize gains on nonmonetary exchanges involving oil and gas properties. According to the provisions of SFAS No. 153, all nonmonetary asset exchanges that have commercial substance, as defined, will be measured at fair value with gain or loss recognized in earnings. Values of historical nonmonetary asset exchanges have not been material.

Assets held for sale

In November 2004, the Company classified certain properties located in Montana as held for sale. The sale of these properties closed in April 2005 for $11.3 million. The Company recorded an associated gain of $6.2 million. The sale included 45 wells and associated reserves of 935,000 barrels of oil at April 1, 2005, the effective date of the transaction. These assets and associated liabilities are shown as held for sale in the 2004 consolidated financial statements.

Income taxes

Effective June 1, 1997, the Company converted to an S-corporation under Subchapter S of the Internal Revenue Code. As a result, income taxes attributable to federal and state taxable income of the Company after May 31, 1997, if any, are payable by the shareholders of the Company. Certain properties held by the Company at the time of the conversion may be subject to federal taxation on the excess of the S-corporation conversion date fair market value over the asset s then taxable basis if sold within 10 years of the conversion to an S-corporation. These taxes are payable by the Company. In 2005, the Company has recorded federal income tax expense of $1.1 million attributable to such gains on sales of properties according to section 1374 of the Internal Revenue Code.

Pro forma information (unaudited)

Pro forma adjustments are reflected on the consolidated balance sheets to adjust for the reclassification of undistributed earnings between retained earnings and additional paid-in capital in connection with the Company s conversion from an S-corporation to a C-corporation in connection with its planned initial public offering as if the conversion had occurred on September 30, 2006.

Pro forma adjustments are reflected on the consolidated statements of income to provide for income taxes in accordance with SFAS No. 109 as if the Company had been a C-corporation for all periods presented. For unaudited pro forma income tax calculations, deferred tax assets and liabilities were recognized for the future tax consequences attributable to differences between the financial statement carrying amounts of existing assets and

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liabilities and their respective tax bases. Deferred tax assets and liabilities were measured using enacted tax rates expected to apply to taxable income in the years in which the Company expects to recover or settle those temporary differences. A statutory Federal tax rate of 35% and effective state tax rate of 3% (net of Federal income tax effects) were used for the pro forma enacted tax rate for all periods. The pro forma tax effects are based upon currently available information. Management believes that these assumptions provide a reasonable basis for representing the pro forma tax effects.

Pro forma adjustments are reflected on the consolidated statements of income to adjust earnings per share for the effect of the Company s planned 11 for 1 stock split to be effected as a stock dividend in connection with the consummation of the Company s planned initial public offering.

Issued and outstanding shares, inclusive of restricted stock, at December 31, 2004 and 2005 and at September 30, 2006, on a historical and pro forma basis, were as follows:

	December 31,		September 30,
	2004	2005	2006
Outstanding shares (historical)	14,368,919	14,458,966	14,457,314
Outstanding shares (pro forma)	158,058,109	159,048,626	159,030,454

The following table sets forth the computation of shares used in the pro forma basic and diluted earnings per share computations for the years ended December 31, 2003, 2004 and 2005 and for the nine months ended September 30, 2005 and 2006:

	Year ended December 31,			Nine months ended September 30,	
	2003 Shares	2004 Shares	2005 Shares	2005 Shares	2006 Shares
Shares used in basic earnings per share	158,058,109	158,058,109	158,058,109	158,058,109	158,058,109
Effect of dilutive securities:					
Restricted stock			160,094		548,977
Employee stock options		1,180,817	1,087,812	1,686,993	1,073,347

Shares used in diluted earnings per share	158,058,109	159,238,926	159,306,015	159,745,102	159,680,433

Comprehensive income

The Company classifies other comprehensive income items by their nature in the consolidated financial statements and displays the accumulated balance of other comprehensive income separately in the shareholders equity section of the balance sheet. Accumulated other comprehensive income at December 31, 2005 consists of foreign currency translation.

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Earnings per common share

Basic earnings per common share is computed by dividing net income by the weighted-average number of shares outstanding for the period. Diluted earnings per share reflects the potential dilution of restricted stock awards and dilutive stock options, which are calculated using the treasury stock method as if these options were exercised. The following tables set forth earnings per share and the computation of shares used in the basic and diluted earning per share computations for the years ended December 31, 2003, 2004 and 2005 and for the nine months ended September 30, 2005 and 2006:

	Year ended December 31,			Nine months ended September 30,	
	2003	2004	2005	2005	2006
Basic income (loss) per share:					
From continuing operations	$ (0.05)	$ 1.87	$ 13.52	$ 9.09	$ 14.55
From discontinued operations	0.06	0.11			
Loss on sale of discontinued operations		(0.04)			
Before cumulative effect of change in accounting principle	0.01	1.94	13.52	9.09	14.55
Cumulative effect of change in accounting principle	0.15				
Net income per share	$ 0.16	$ 1.94	$ 13.52	$ 9.09	$ 14.55
Diluted income (loss) per share:					
From continuing operations	$ (0.05)	$ 1.85	$ 13.42	$ 9.00	$ 14.40
From discontinued operations	0.06	0.12			
Loss on sale of discontinued operations		(0.04)			
Before cumulative effect of change in accounting principle	0.01	1.93	13.42	9.00	14.40
Cumulative effect of change in accounting principle	0.15				
Net income per share	$ 0.16	$ 1.93	$ 13.42	$ 9.00	$ 14.40

	Year ended December 31,	Nine months ended September 30,

	2003 Shares	2004 Shares	2005 Shares	2005 Shares	2006 Shares
Shares used in basic earnings per share	14,368,919	14,368,919	14,368,919	14,368,919	14,368,919
Effect of dilutive securities:					
Restricted stock			14,554		49,907
Employee stock options		107,347	98,892	153,363	97,577
Shares used in diluted earnings per share	14,368,919	14,476,266	14,482,365	14,522,282	14,516,403

Accounting for derivatives

The Company had no open hedges at December 31, 2004 or 2005. Previously, the Company periodically utilized derivative contracts to hedge the commodity price risk associated with specifically identified purchase or sales contracts, oil and gas production or operational needs. The Company accounted for its non-trading

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derivative activities under the guidance provided by SFAS No. 133, Accounting for Derivative Instruments and Hedging Activities , as amended, and recognized all of its derivative instruments as assets or liabilities in the balance sheet at fair value with such amounts classified as current or long-term based on their anticipated settlement. The accounting for the changes in fair value of a derivative depends on the intended use of the derivative and resulting designation.

Fair value of financial instruments

The Company s financial instruments consist primarily of cash, trade receivables, trade payables and bank debt. The carrying value of cash, trade receivables and trade payables are considered to be representative of their respective fair values, due to the short maturity of these instruments.

The fair value of long-term debt approximates its carrying value based on the borrowing rates currently available to the Company for bank loans with similar terms and maturities. The estimated fair value of long-term debt is $280.0 million and $143.0 million at December 31, 2004 and 2005, respectively.

Equity compensation

The Company accounts for employee stock option grants and restricted stock grants under Accounting Principles Board Opinion No. 25, Accounting for Stock Issued to Employees using the intrinsic method, as permitted by SFAS 123. The terms of the restricted stock grants and stock option grants stipulate that, while the Company is a private company, it is required to purchase the vested restricted stock and stock acquired from stock option exercises at each employee s request based upon the purchase price as determined by a formula specified in each award agreement. Additionally, the Company has the right to purchase vested restricted stock and stock acquired from stock option exercises at the same price upon termination of employment for any reason and for a period of two years subsequent to leaving the employment of the Company. The Company measures compensation cost for the awards based upon the formula purchase price which is determined by calculating a per share value for shareholders equity adjusted for the excess of each period s ending PV-10 oil and gas reserve valuation over the book value of oil and gas properties. The amounts subject to the purchase are reflected on the accompanying consolidated balance sheets as liabilities of $2.4 million and $12.2 million as of December 31, 2004 and 2005, respectively, and $17.2 million at September 30, 2006. The Company s associated compensation expense, as included in general and administrative expense, was $197,000, $2.0 million and $13.7 million during 2003, 2004 and 2005, respectively, and $12.3 million and $5.0 million for the nine months ended September 30, 2005 and 2006, respectively.

The right to sell and requirement to purchase will lapse when the Company becomes a reporting company under Section 12 of the Exchange Act. Upon becoming a reporting company under Section 12 of the Exchange Act, the Company will be required to record a charge to earnings to adjust the plan determined share price to the price received in an initial public offering and account for the grants under the fair value provisions of SFAS 123(R) thereafter.

Recent accounting pronouncements

In December 16, 2004, the FASB issued SFAS 123(R), Share-Based Payment, a revision of SFAS 123, and APB Opinion 25, Accounting for Stock Issued to Employees . SFAS 123(R) requires that the cost of share- based payment transactions (including those with employees and non-employees) be recognized in the financial statements. SFAS 123(R) applies to all share-based payment transactions in which an entity acquires goods or

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services by issuing (or offering to issue) its shares, share options or other equity instruments (except for those held by ESOP) or by incurring liabilities (1) in amounts based on the price of the entity s shares or other equity instruments or (2) that require (or may require) settlement by the issuance of an entity s share or other equity instruments. SFAS 123 (R) is effective for the Company in the first annual reporting period after December 15, 2005. The Company will implement SFAS 123(R) on January 1, 2006 using the modified prospective application. The adoption of SFAS 123 (R) is not expected to have a material effect on the Company s consolidated financial statements.

On June 1, 2005, the FASB issued FASB Statement No. 154, Accounting Changes and Error Corrections (SFAS No. 154), which will require entities that voluntarily make a change in accounting principle to apply that change retrospectively to prior periods financial statements, unless this would be impracticable. SFAS No. 154 supersedes Accounting Principles Board Opinion No. 20, Accounting Changes (APB 20), which previously required that most voluntary changes in accounting principle be recognized by including in the current period s net income the cumulative effect of changing to the new accounting principle. SFAS No. 154 also makes a distinction between retrospective application of an accounting principle and the restatement of financial statements reflects the correction of an error.

Another significant change in practice under SFAS No. 154 will be that if an entity changes its method of depreciation, amortization, or depletion for long-lived, non-financial assets, the change must be accounted for as a change in accounting estimate. Under APB 20, such a change would have been reported as a change in accounting principle. SFAS No. 154 applies to accounting changes and error corrections that are made in fiscal years beginning after December 15, 2005. Management has not completed its assessment of the impact of SFAS No. 154, but does not anticipate any material impact from implementation of this accounting standard.

In April 2005, the FASB issued Staff Position No. FAS 19-1, Accounting for Suspended Well Costs . FSP 19-1 amended paragraphs 31-34 of SFAS No. 19, to allow continued capitalization of exploratory well costs beyond one year from the completion of drilling under circumstances where the well has found a sufficient quantity of reserves to justify its completion as a producing well and the enterprise is making sufficient progress assessing the reserves and the economic and operating viability of the project. The guidance in FSP 19-1 was effective for the first reporting period beginning after April 4, 2005. The Company adopted the new requirements and does not have any capitalized exploratory well costs beyond one year from the completion of drilling.

In September 2006, the Securities and Exchange Commission issued Staff Accounting Bulletin (SAB) No. 108, *Considering the Effects of Prior Year Misstatements when Quantifying Current Year Misstatements*. SAB No. 108 requires analysis of misstatements using both an income statement (rollover) approach and a balance sheet (iron curtain) approach in assessing materiality and provides for a one-time cumulative effect transition adjustment. The Company has applied the guidance of SAB No. 108 for all periods presented.

In June 2006, the FASB issued Interpretation No. 48, *Accounting for Uncertainty in Income Taxes* (FIN 48). The interpretation clarifies the accounting for uncertainty in income taxes recognized in a company s financial statements in accordance with Statement of Financial Accounting Standards No. 109, *Accounting for Income Taxes*. The interpretation is effective for fiscal years beginning after December 15, 2006. The adoption of FIN 48 is not expected to have a material impact on the Company s consolidated financial position or results of operations.

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In September 2006, the FASB finalized SFAS No. 157, *Fair Value Measurements* which will become effective in 2008. This Statement defines fair value, establishes a framework for measuring fair value, and expands disclosures about fair value measurements; however, it does not require any new fair value measurements. The provisions of SFAS No. 157 will be applied prospectively to fair value measurements and disclosures in the Company s Consolidated Financial Statements beginning in the first quarter of 2008. The adoption of SFAS No. 157 is not expected to have a material impact on the Company s consolidated financial position or results of operations.

2. Hedging Contracts

The Company has utilized fixed-price contracts and zero-cost collars in the past to reduce exposure to unfavorable changes in oil and gas prices that are subject to significant and often volatile fluctuation. Under the fixed price delivery contracts the Company received the fixed price stated in the contract. Under the zero-cost collars, if the market price of crude oil exceeded the ceiling strike price or fell below the floor strike price, then the Company received the applicable collar strike price. If the market price was between the floor strike price and the ceiling strike price, the Company received market price.

The Company was not a party to any open hedge contracts at December 31, 2004 or 2005. Charges in the amounts of $10.1 million and $6.4 million for hedging activities are reported as a reduction in oil and gas sales in the income statement for the years ended December 31, 2003 and 2004, respectively.

At December 31, 2003, the Company had a crude oil derivative contract in place, which was being marked to market under SFAS No. 133, Accounting for Derivative Instruments and Hedging Activities, with changes in fair value being recorded in earnings as such contract did not qualify for special hedge accounting. At December 31, 2003, the Company recorded a net gain of $1.5 million in crude oil marketing and trading revenue in connection with this contract.

The Company recognized no significant amounts due to hedge ineffectiveness in any year presented.

3. Long-term Debt

The Company had the following long-term debt outstanding as of the dates shown (in thousands):

	December 31,	
	2004	2005
Credit facility due March 31, 2007	$ 230,000	$ 143,000
Subordinated note due to shareholder March 31, 2008	50,000	
Vehicle credit agreements	31	
Outstanding debt	280,031	143,000
Less current portion	12	
Total long-term debt	$ 280,019	$ 143,000

On November 22, 2004, the Company executed a Fifth Amended and Restated Credit Agreement in which a group of lenders agreed to provide a $400.0 million senior secured revolving credit facility with a commitment of

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$250.0 million as of December 31, 2005. Borrowings under the credit facility are secured by liens on substantially all oil and gas properties and associated assets of the Company.

On March 23, 2005, the Company executed the First Amendment to the Credit Agreement and revised the pricing grid, which lowered the Utilization Percentage and the LIBOR margins. On December 7, 2005, the Company executed the Second Amendment to the Credit Agreement in order to terminate certain covenants including a requirement to hedge certain quantities of our production under various conditions.

Borrowings under the credit facility currently bear interest, payable quarterly, at

A rate per annum equal to the London Interbank Offered Rate (LIBOR) for one, two, three or six months, as elected by the Company, plus a margin ranging from 125 to 200 basis points, or

At the lead banks reference rate plus an applicable margin ranging from 25 to 50 basis points.

The Company has $107.0 million available under the credit facility at December 31, 2005 and incurred approximately $245,000 in commitment fees during 2005. These fees are 0.375% of the daily average excess of the commitment amount over the outstanding credit balance. Fees are payable five business days after the end of each quarter. The Company paid approximately $2.0 million in debt issuance fees for the new credit facility, which was capitalized and is being amortized on a straight-line basis over the life of the credit facility. The credit facility matures on March 31, 2007. The Company s weighted average interest rate was 6.08% at December 31, 2005. The Company s credit facility contains certain financial and certain information reporting covenants. As of December 31, 2005, the Company was in compliance with all covenants.

The Company redeemed $119.5 million of Senior Subordinated 10.25% Notes during November 2004 and paid a premium of $4.1 million due to early redemption of the notes.

On November 22, 2004, the Company signed a note with its principal shareholder for $50.0 million. The annual rate of interest was 6.00% and interest payments were due the last day of each calendar quarter beginning December 31, 2004. The maturity date of the note was March 31, 2008. A subordination agreement was executed making the $50.0 million note to the Company subordinate to the Credit Agreement discussed above. In January 2005, the principal shareholder contributed $2.0 million of the previously loaned amount to the Company. The $2.0 million contribution is reflected in additional paid in capital. The Company paid the outstanding balance of $48.0 million in December 2005.

At December 31, 2005, the Company had $0.9 million of outstanding letters of credit that expire during 2006 and a $1.0 million outstanding letter of credit that expires during 2007.

Long term debt (unaudited)

On April 12, 2006, the Company amended the credit facility. The amended facility matures on April 12, 2011. At the Company s election, the maturity date can be extended for up to two one-year periods. Borrowings under the facility bear interest, payable quarterly, at a rate per annum equal to the London Interbank Offered Rate for one, two, three or six months, as elected by the Company, plus a margin ranging from 100 to 175 basis points or the lead banks reference rate. The amended facility has a note amount of $750 million, a borrowing base of

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$500 million, subject to semi-annual redetermination, and a commitment level of $300 million. Under the terms of the amended facility the Company is allowed to set the commitment level at any level up to the borrowing base.

The amended facility contains certain covenants including that the Company maintain a current ratio of not less than 1.0 to 1.0 and a Total Funded Debt to EBITDAX of no greater than 3.75 to 1.0. The Company was in compliance with these covenants at September 30, 2006.

The Company had outstanding borrowings of $131.5 million under the previous credit facility on March 31, 2006 and $199.5 million on April 12, 2006 immediately after closing on the amended facility. Borrowings on April 12, 2006 reflected incurrence of additional borrowings in connection with the Company s $60.0 million dividend which was accrued at March 31, 2006 and paid on April 13, 2006.

4. Cash Flow Information

Net cash provided by operating activities reflects cash payments for interest as follows (in thousands):

	2003	2004	2005
Interest paid	$ 20,386	$ 29,313	$ 14,598

Noncash investing and financing activities are as follows (in thousands):

	2003	2004	2005
Capital contribution note payable forgiven by shareholder	$	$	$ 2,000
Cancellation of capital leases			10,058

Effective January 1, 2003, the Company adopted SFAS No. 143 and recorded the asset retirement obligations as follows (in thousands):

	2003
Increase in property and equipment	$ 27,798
Increase in asset retirement obligation	(25,636)
Cumulative effect of accounting change	$ 2,162

5. Property, Plant, and Equipment

Property, plant and equipment includes the following at December 31, 2004 and 2005 (in thousands):

	2004	2005
Proved oil and gas properties	$ 645,752	$ 753,841
Unproved oil and gas properties	22,803	32,785
Service properties, equipment and other	19,102	19,790
Total property and equipment	687,657	806,416
Accumulated depreciation, depletion and amortization	(253,318)	(297,023)
Net property and equipment	$ 434,339	$ 509,393

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6. Accrued Liabilities

Accrued liabilities includes the following at December 31, 2004 and 2005 (in thousands):

	2004	2005
Equity compensation	$ 2,387	$ 12,186
Production taxes and income taxes	4,581	9,417
Drilling cost advances from third parties	2,998	2,295
Interest	1,030	652
Other	1,545	4,245
Total accrued liabilities	$ 12,541	$ 28,795

7. Lease Commitments

The Company leases office space under operating leases from the principal shareholder (See Note 11).

The Company had a capital lease arrangement to lease compressors in place at December 31, 2004 from a related party. The assets related to these capital leases totaled $16.8 million at December 31, 2004, with accumulated depreciation of $3.5 million at December 31, 2004. Subsequent to December 31, 2004, the capital lease contract was cancelled and the Company executed an operating lease effective January 28, 2005. The Company pays approximately $400,000 per month under the operating lease. The term of the operating lease is through January 28, 2009.

Lease expense associated with the Company s operating leases for the years ended December 31, 2003, 2004 and 2005, was $627,000, $725,000 and $5.3 million, respectively. At December 31, 2005, including leases renewed and entered into subsequent to December 31, 2005, the minimum future rental commitments under operating leases having non-cancelable lease terms in excess of one year, including leases from related parties, are as follows (in thousands):

Year	Leases with Related Parties	Leases with Non-Related Parties	Total Amount
2006	$ 4,919	$ 320	$ 5,239
2007	4,819	305	5,124
2008	4,819	247	5,066
2009	402	91	493
2010		22	22
Total obligations	$ 14,959	$ 985	$ 15,944

8. Shareholders Equity

On December 8, 2004, the Company s Amended and Restated Certificate of Incorporation was amended to convert 1,000,000 shares of common stock to voting common stock, par value $.01 per share, and 19,000,000 shares of common stock to non-voting common stock, par value $.01 per share. Each share of common stock, par value $.01 per share, outstanding was converted and reclassified into 5% voting common stock and 95%

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non-voting stock. At December 31, 2004 and 2005, there were 718,446 voting shares and 13,650,473 and 13,740,520 of non-voting shares, respectively.

The Company paid dividends of $60.0 million and $27.6 million on April 13, 2006 and August 15, 2006, respectively, to existing shareholders and, subject to forfeiture, to holders of unvested restricted stock.

9. Stock Compensation

The Company has outstanding options and/or shares of restricted stock issued under two incentive plans, the Continental Resources, Inc. 2000 Stock Option Plan (2000 Plan), which was terminated November 10, 2005, and the Continental Resources, Inc. 2005 Long-Term Incentive Plan (2005 Plan).

Effective October 1, 2000, the Company adopted the 2000 Plan and granted options to eligible employees. These options were either Incentive Stock Options, Nonqualified Stock Options, or a combination of both. The granted stock options vest over a five-year period at the rate of 20% each year for the Incentive Stock Options and over a three year period at the rate of 33 $^{1}/3$% for the Nonqualified Stock Options, both commencing on the first anniversary of the grant date. The maximum number of shares covered consisted of 1,020,000 shares of the Company s common stock, par value $.01 per share. As of December 31, 2005, options covering 65,000 shares had been exercised. On November 10, 2005, the 2000 Plan was terminated and 152,000 shares of common stock previously granted, par value $0.01 per share, remained reserved for unexercised stock options previously granted under the 2000 Plan.

The Company s stock option grants are as follows:

	Number of options outstanding	Weighted average exercise price	Number of options exercisable	Weighted average exercise price
Outstanding December 31, 2002	172,000	$ 10.79	72,002	$ 10.50
Granted				
Exercised				
Canceled				

Outstanding December 31, 2003	172,000	10.79	114,933	10.34
Granted	20,000	43.62		
Exercised	(25,000)	12.60		
Canceled				
Outstanding December 31, 2004	167,000	14.45	118,866	10.39
Granted	25,000	62.82		
Exercised	(40,000)	10.50		
Canceled				
Outstanding December 31, 2005	152,000	$ 23.44	109,667	$ 12.59

The recorded liability associated with the exercise of options during 2004 and 2005 was settled in cash. Shares of common stock were never issued and the Company s outstanding common stock did not change as a result of the options exercise.

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The following table summarizes information about stock options outstanding at December 31, 2005:

	Options Outstanding			Options Exercisable	
Range of Exercise Prices	**Number Outstanding**	**Weighted Average Remaining Contractual Life**	**Weighted Average Exercise Price**	**Number Exercisable**	**Weighted-Average Exercise Price**
$7.00 - $7.77	57,000	5.53 years	$ 7.38	53,000	$ 7.35
$14.00	50,000	4.75 years	14.00	50,000	14.00
$43.62	20,000	8.58 years	43.62	6,667	43.62
$62.82	25,000	9.33 years	62.82		
	152,000		$ 23.44	109,667	$ 12.59

On October 3, 2005, the Company adopted the 2005 Plan and reserved a maximum of 500,000 shares of non-voting common stock that may be issued pursuant to the 2005 Plan. As of December 31, 2005, the Company had outstanding 90,047 shares of restricted stock granted to directors, officers and key employees under the plan. All grants were made on or after October 3, 2005. Restricted stock is awarded in the name of the recipient and except for the right of disposal, constitutes issued and outstanding shares of the Company s common stock for all corporate purposes during the period of restriction including the right to receive dividends, subject to forfeiture. Restricted stock grants vest ratably over a three-year period.

Pursuant to the award agreements the Company has the right to purchase vested restricted shares and shares acquired by option exercise at all times the employee remains in the employment of the Company and for a period of two years subsequent to leaving the employment of the Company and grantees have the right to require the Company to purchase vested restricted shares and shares acquired by option exercise, each at a purchase price as determined by a formula specified in each award agreement. All grants of stock options and restricted stock were issued at the then estimated formula purchase price of the Company s stock determined according to the plans. In accordance with the plans, the Company calculates the formula purchase price quarterly based on shareholders equity adjusted for the excess of period end PV-10 oil and gas reserve valuation over the book value of oil and gas properties. Compensation expense is recognized over the vesting period and was $197,000, $2.0 million and $13.7 million for the years ended December 31, 2003, 2004, and 2005, respectively.

Effective January 1, 2006, the Company adopted SFAS No. 123(R), using the modified-prospective transition method. As the Company s employee stock options and restricted stock awards have been accounted for as liability awards, and adjusted to the formula price as prescribed by the plan at the end of each reporting period, the adoption did not change the accounting for the awards. The Company recognized compensation expense of $5.0 million for the nine months ended September 30, 2006.

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The following tables disclose the activity in employee stock options and restricted shares for the nine months ended September 30, 2006 as required by SFAS 123(R):

Restricted Stock

A summary of changes in the status of the non-vested shares for the nine months ended September 30, 2006, is presented below:

	Number of Non-vested Shares	Weighted Average Grant-Date Fair Value
Non-vested shares as of December 31, 2005	90,047	$ 147.42
Granted	5,550	149.11
Vested		
Forfeited	(7,202)	147.39
Non-vested shares as of September 30, 2006	88,395	$ 147.53

As of September 30, 2006, there was $5.8 million of unrecognized compensation expense related to non-vested restricted stock. The expense is expected to be recognized over a weighted average period of 2.2 years.

Stock Options

The following table provides information related to stock option activity for the nine months ended September 30, 2006:

	Number of Shares	Weighted Average	Weighted Average	Aggregate Intrinsic

	Underlying Options	Exercise Price Per Share	Contract Life in Years	Value (1)
Outstanding at December 31, 2005	152,000	$ 23.44		
Granted				
Exercised				
Forfeited				
Outstanding at September 30, 2006	152,000	$ 23.44	5.55	$ 8,288
Exercisable at September 30, 2006	127,000	$ 17.45	5.03	$ 7,666

(1) The intrinsic value of a stock option is the amount by which the formula derived value of the underlying stock exceeds the exercise price of the option.

As of September 30, 2006, there was $680,000 of unrecognized compensation expense related to non-vested stock options. The expense is expected to be recognized over a weighted average period of 1.1 years.

10. Commitments and Contingencies

The Company maintains a defined contribution retirement plan for its employees and makes discretionary contributions to the plan based on a percentage of eligible employees compensation, excluding bonuses. During 2003, 2004 and 2005, contributions to the plan were 5% of eligible employees compensation, excluding

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(Information as of September 30, 2006 and for the nine months ended September 30, 2005 and 2006 are unaudited)

bonuses. Expense for the years ended December 31, 2003, 2004 and 2005, was $404,000, $431,000 and $663,000, respectively.

The Company and other affiliated companies participate in a self-insurance pool (the Pool) covering health and workers compensation claims made by employees up to the first $100,000 and $250,000, respectively, per claim. Any amounts paid above these are reinsured through third-party providers. Allocations between the Company and other affiliated companies are based on estimated costs per employee of the Pool.

Property and general liability insurance is maintained through third-party providers with a $100,000 deductible on each policy. In combination with excess liability coverage the Company has insurance up to $35 million in place. The Company had no pending claims at December 31, 2005.

The Company is involved in various legal proceedings in the normal course of business, none of which, in the opinion of management, will have a material adverse effect on the financial position or results of operations of the Company. As of December 31, 2005 and September 30, 2006, the Company has provided a reserve of $520,000 and $740,000, respectively, for various matters none of which are believed to be individually significant.

Due to the nature of the oil and gas business, the Company is exposed to possible environmental risks. The Company is not aware of any material environmental issues or claims.

11. Related Party Transactions

The Company markets a portion of its oil and natural gas to various affiliates. During the years ended December 31, 2003, 2004, and 2005, these sales were approximately $4.8 million, $19.0 million, and $108.9 million. The Company also contracts for field services such as compression and drilling rig services and purchases residue fuel gas and reclaimed oil from certain affiliates. Production expense to these affiliates was $8.1 million, $7.0 million and $13.0 million for the years ended December 31, 2003, 2004 and 2005, respectively. The total amount paid to these companies, a portion of which was billed to other interest owners, was approximately $18.4 million, $23.4 million and $38.6 million during the years ended December 31, 2003, 2004 and 2005, respectively. At December 31, 2004 and 2005, approximately $8.0 million and $42.1 million was due from affiliates and approximately $3.3 million and $3.1 million was due to affiliates.

Affiliates of the Company, owned by the Company s principal shareholder and in one instance by an officer of the Company, also own working and royalty interests in wells operated by the Company. We paid revenues, including royalties, of approximately $0.7 million, $1.8 million, and $5.6 million and billed expenses of $1.1 million, $1.4 million, and $4.2 million during the years ended December 31, 2003, 2004, and 2005 to these affiliates and this officer.

As described in Note 12, the assets of CGI were sold to shareholders during 2004. During July 2005, the Company acquired oil and gas assets from the Company s principal shareholder for $4.5 million.

The Company leases office space under operating leases from the principal shareholder. Rents paid associated with these leases totaled approximately $505,000, $506,000 and $556,000 for the years ended December 31, 2003, 2004 and 2005, respectively. The term of these leases is through February 2007 at an annual rate of $646,000.

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Continental Resources, Inc. and Subsidiary

Notes to Consolidated Financial Statements (continued)

(Information as of September 30, 2006 and for the nine months ended September 30, 2005 and 2006 are unaudited)

On November 22, 2004, the Company entered into a subordinated note with the principal shareholder, which required the Company to make quarterly interest payments beginning December 31, 2004. Interest paid during 2004 and 2005 was $308,000 and $2.9 million, respectively. During 2005, the principal shareholder forgave $2.0 million of this note and a contribution to paid-in capital was recorded. The outstanding balance of $48.0 million was paid on December 27, 2005. (Note 3)

12. Discontinued Operations

In July 2004, the Company completed the sale of all of the outstanding stock in CGI to the Company s shareholders for $22.6 million in cash. The sales price was representative of the fair value of the net assets based on an appraisal by an independent third party who also provided the Company with an opinion of the fairness from a financial point of view, of the sale of CGI to the Company s shareholders. The CGI assets included seven gas gathering systems and three gas-processing plants. These assets represented the entire gas gathering, marketing and processing segment of the Company and have been classified as discontinued operations for all periods presented.

The assets and liabilities of CGI as of July 21, 2004, included within the related discontinued operations are as follows (in thousands):

Cash	$ 1,681
Accounts receivable	9,592
Inventories	153
Prepaid expenses	4
Total current assets of discontinued operations	11,430
Property and equipment, net	38,894
Other noncurrent assets	225
Total noncurrent assets of discontinued operations	39,119
Total assets	$ 50,549
Accounts Payable	$ 10,566
Current portion of long-term debt	2,429
Accrued expense and other current liabilities	92
Total current liabilities of discontinued operations	13,087
Long-term debt, net of current portion	13,357
Other noncurrent liabilities	377

Total noncurrent liabilities of discontinued operations	13,734
Shareholders equity	23,728
Total liabilities and shareholders equity	$ 50,549

The results of operations of CGI prior to its disposition are included within income from discontinued operations in the following periods (in thousands):

	December 31,	
	2003	**2004**
Revenues	$ 76,018	$ 50,956
Income from discontinued operations	946	1,680

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Continental Resources, Inc. and Subsidiary

Notes to Consolidated Financial Statements (continued)

(Information as of September 30, 2006 and for the nine months ended September 30, 2005 and 2006 are unaudited)

13. Oil and Gas Property Information

The following table sets forth the Company s results of operations from oil and natural gas producing activities for the years ended December 31, 2003, 2004 and 2005 (in thousands):

	December 31,		
	2003	2004	2005
Oil and gas sales	$ 138,948	$ 181,435	$ 361,833
Production expense and tax	(51,072)	(56,051)	(68,785)
Exploration expense	(17,221)	(12,633)	(5,231)
Accretion of asset retirement obligation	(1,137)	(1,029)	(1,596)
Depreciation, depletion and amortization	(37,329)	(36,193)	(46,829)
Property impairments	(8,975)	(11,747)	(6,930)
Results from oil and gas producing activities	$ 23,214	$ 63,782	$ 232,462

	December 31,		
	2003	2004	2005
Pro forma presentation for income tax (unaudited)			
Results from oil and gas producing activities before pro forma income tax	$ 23,214	$ 63,782	$ 232,462
Pro forma income tax	(8,821)	(24,237)	(88,336)
Results from oil and gas producing activities after pro forma income tax	$14,393	$ 39,545	$ 144,126

Costs incurred in oil and gas activities

Costs incurred, both capitalized and expensed, in connection with the Company s oil and gas acquisition, exploration and development activities for the three years ended December 31, 2003, 2004 and 2005 are shown below (in thousands).

	2003	2004	2005
Property acquisition costs:			
Proved	$ 180	$ 756	$ 2,267
Unproved	8,503	11,700	14,496
Total property acquisition costs	8,683	12,456	16,763
Exploration costs	11,981	30,867	9,289
Development costs	75,396	53,036	117,837
Total	$ 96,060(1)	$ 96,359	$ 143,889

(1) Excludes $15,528 of cumulative asset retirement cost recorded to adopt the provisions of SFAS No. 143 on January 1, 2003.

Exploration costs above include asset retirement costs of $123,000, $244,000 and $305,000 and development costs above include asset retirement costs of $553,000, $6,998,000 and $726,000 for the years 2003, 2004 and 2005, respectively.

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Notes to Consolidated Financial Statements (continued)

(Information as of September 30, 2006 and for the nine months ended September 30, 2005 and 2006 are unaudited)

Aggregate capitalized costs

Aggregate capitalized costs relating to the Company s oil and gas producing activities, and related accumulated depreciation, depletion and amortization, as of December 31, 2004 and 2005 are as follows (in thousands):

	2004	2005
Proved oil and gas properties	$ 645,752	$ 753,841
Unproved oil and gas properties	22,803	32,785
Total	668,555	786,626
Less-accumulated DD&A	(240,030)	(283,036)
Net capitalized costs	$ 428,525	$ 503,590

Under the successful efforts method of accounting, the costs of drilling an exploratory well are capitalized pending determination of whether proved reserves can be attributed to the discovery. When initial drilling operations are complete, management determines whether the well has discovered oil and gas reserves and, if so, whether those reserves can be classified as proved. Often, the determination of whether proved reserves can be recorded under strict Securities and Exchange Commission (SEC) guidelines cannot be made when drilling is completed. In those situations where management believes that commercial hydrocarbons have not been discovered, the exploratory drilling costs are reflected in the Consolidated Income Statement as dry hole costs (a component of exploration expense). Where sufficient hydrocarbons have been discovered to justify further exploration or appraisal activities, exploratory drilling costs are deferred on the Consolidated Balance Sheet pending the outcome of those activities.

At the end of each quarter, operating and financial management review the status of all deferred exploratory drilling costs in light of ongoing exploration activities in particular, whether the company is making sufficient progress in its ongoing exploration and appraisal efforts. If management determines that future appraisal drilling or development activities are not likely to occur in the future, any associated exploratory well costs are expensed in that period.

The following table presents the amount of capitalized exploratory drilling costs pending evaluation at December 31 for each of the last three years and changes in those amounts during the years then ended (in thousands):

	2003	2004	2005
Balance, January 1	$ 4,807	$ 814	$ 3,237
Additions to capitalized exploratory well costs pending determination of proved reserves	11,858	30,024	8,984
Reclassification to proved oil and gas properties based on the determination of proved reserves	(2,285)	(18,112)	(8,915)
Capitalized exploratory well costs charged to expense	(13,566)	(9,489)	(1,432)
Balance, December 31	$ 814	$ 3,237	$ 1,874

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Continental Resources, Inc. and Subsidiary

Notes to Consolidated Financial Statements (continued)

(Information as of September 30, 2006 and for the nine months ended September 30, 2005 and 2006 are unaudited)

14. Supplemental Oil and Gas Information (Unaudited)

The following table shows estimates of proved reserves prepared by the Company s technical staff and independent external reserve engineers in accordance with SEC definitions. Ryder Scott Company prepared reserve estimates for properties comprising 83% of our standardized measure of discounted future net cash flows as of December 31, 2003, 2004 and 2005. Remaining reserve estimates were prepared by our technical staff. Substantially all reserves stated here are located in the United States of America.

Proved reserves are estimated quantities of crude 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.

There are numerous uncertainties inherent in estimating quantities of proved oil and natural gas reserves. Oil and natural gas reserve engineering is a subjective process of estimating underground accumulations of oil and natural gas that cannot be precisely measured, and estimates of engineers other than the Company s might differ materially from the estimates set forth herein. The accuracy of any reserve estimate is a function of the quality of available data and of engineering and geological interpretation and judgment. Results of drilling, testing and production subsequent to the date of the estimate may justify revision of such estimate. Accordingly, reserve estimates are often different from the quantities of oil and gas that are ultimately recovered.

Gas imbalance receivables and liabilities for each of the three years ended December 31, 2003, 2004 and 2005, were not material and have not been included in the reserve estimates.

	Natural Gas (MMcf)	Crude Oil (MBbls)
Proved reserves as of December 31, 2002	69,947	63,281
Revisions of previous estimates	(2,634)	647
Extensions, discoveries and other additions	12,567	12,853
Production	(10,751)	(3,463)
Sale of minerals in place	(2,033)	(318)
Purchase of minerals in place		
Proved reserves as of December 31, 2003	67,096	73,000
Revisions of previous estimates	1,257	3,172

Extensions, discoveries and other additions	554	7,918
Production	(8,794)	(3,688)
Sale of minerals in place		
Purchase of minerals in place	507	200
Proved reserves as of December 31, 2004	60,620	80,602
Revisions of previous estimates	1,431	1,653
Extensions, discoveries and other additions	54,823	23,290
Production	(9,006)	(5,708)
Sale of minerals in place		(1,292)
Purchase of minerals in place	250	100
Proved reserves as of December 31, 2005	108,118	98,645

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Continental Resources, Inc. and Subsidiary

Notes to Consolidated Financial Statements (continued)

(Information as of September 30, 2006 and for the nine months ended September 30, 2005 and 2006 are unaudited)

Proved oil and gas reserves

The following reserve information sets forth the estimated quantities of proved developed and proved undeveloped oil and natural gas reserves of the Company as of December 31, 2003, 2004 and 2005:

Proved Developed Reserves	Natural Gas (MMcf)	Crude Oil (MBbls)	Oil Equivalent (MBoe)
December 31, 2003	63,327	36,106	46,661
December 31, 2004	56,733	65,594	75,050
December 31, 2005	54,257	71,259	80,302
Proved Undeveloped Reserves	**Natural Gas (MMcf)**	**Crude Oil (MBbls)**	**Oil Equivalent (MBoe)**
December 31, 2003	3,769	36,894	37,522
December 31, 2004	3,887	15,008	15,656
December 31, 2005	53,861	27,386	36,363

Proved developed reserves are proved reserves expected to be recovered through existing wells with existing equipment and operating methods. Proved undeveloped reserves are proved reserves that require incremental capital expenditures to recover. Natural gas is converted to barrels of oil equivalent using a conversion factor of six thousand cubic feet per barrel.

Standardized measure of discounted future net cash flows relating to proved oil and gas reserves

The standardized measure of discounted future net cash flows presented in the following table was computed using year-end prices and costs and a 10% discount factor. However, the Company cautions that actual future net cash flows may vary considerably from these estimates. Although the Company s estimates of total proved reserves, development costs and production rates were based on the best available information, the development and production of the oil and gas reserves may not occur in the periods assumed. Actual prices realized, costs incurred and production quantities may vary significantly from those used. Therefore, such estimated future net cash flows computations should not be considered to represent the Company s estimate of the expected revenues or the current value of existing proved reserves.

	2003	2004	2005
		(in thousands)	
Historical			
Future cash inflows	$ 2,666,290	$ 3,562,595	$ 6,332,258
Future production costs	(1,016,316)	(1,280,180)	(1,808,654)
Future development and abandonment costs	(64,978)	(113,390)	(434,249)
Future net cash flows	1,584,996	2,169,025	4,089,355
10% annual discount for estimated timing of cash flows	(769,772)	(1,054,705)	(1,884,980)
Standardized measure of discounted future net cash flows	$ 815,224	$ 1,114,320	$ 2,204,375
Pro forma for income tax			
Future cash inflows	$ 2,666,290	$ 3,562,595	$ 6,332,258
Future production costs	(1,016,316)	(1,280,180)	(1,808,654)
Future development and abandonment costs	(64,978)	(113,390)	(434,249)
Future income taxes	(552,872)	(775,620)	(1,497,230)
Future net cash flows pro forma for income taxes	1,032,124	1,393,405	2,592,125
10% annual discount for estimated timing of cash flows	(501,263)	(677,450)	(1,194,834)
Standardized measure of discounted future net cash flows	$ 530,861	$ 715,955	$ 1,397,291

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Continental Resources, Inc. and Subsidiary

Notes to Consolidated Financial Statements (continued)

(Information as of September 30, 2006 and for the nine months ended September 30, 2005 and 2006 are unaudited)

The year-end weighted average oil price utilized in the computation of future cash inflows was $30.49, $40.46, and $55.87 per barrel at December 31, 2003, 2004 and 2005, respectively. The year-end weighted average natural gas price utilized in the computation of future cash inflows was $4.64, $4.97, and $7.60 per Mcf at December 31, 2003, 2004 and 2005, respectively. Future cash flows are reduced by estimated future costs to develop and to produce the proved reserves, as well as certain abandonment costs based on year-end cost estimates assuming continuation of existing economic conditions.

Income taxes were not computed at December 31, 2003, 2004 or 2005, as the Company elected S-corporation status effective June 1, 1997. The changes in the aggregate standardized measure of discounted future net cash flows attributable to the Company s proved oil and gas reserves are presented below for each of the past three years (in thousands):

	2003	2004	2005
Standardized measure of discounted future net cash flows at the beginning of the year	$ 633,397	$ 815,224	$ 1,114,320
Extensions, discoveries and improved recovery, less related costs	142,663	108,634	566,858
Revisions of previous quantity estimates	1,998	57,525	43,338
Changes in estimated future development and abandonment costs	(49,035)	(44,323)	(317,286)
Purchase (sales) of minerals in place	(4,823)	1,311	(8,714)
Net changes in prices and production costs	54,132	210,323	870,255
Accretion of discount	63,340	81,522	111,432
Sales of oil and gas produced, net of production costs	(91,677)	(125,850)	(287,817)
Development costs incurred during the period	46,290	12,604	48,894
Change in timing of estimated future production, and other	18,939	(2,650)	63,095
Net Change	181,827	299,096	1,090,055
Standardized measure of discounted future net cash flows at the end of the year	$ 815,224	$ 1,114,320	$ 2,204,375

15. Recent Events (Unaudited)

Concurrent with a proposed initial public offering, the Company will convert from a subchapter S-corporation to a subchapter C-corporation. In connection with this conversion, a charge to earnings estimated to be $152.9 million as of September 30, 2006 will be recorded to recognize deferred taxes.

Banner Pipeline Company, L.L.C. was one of the affiliated companies who marketed a portion of our oil sales and was wholly owned by our principal shareholder. On March 30, 2006, we acquired Banner Pipeline Company, L.L.C. for approximately $8.8 million, which represented the book value of working capital, principally cash, accounts receivable, crude oil inventory and accounts payable.

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Glossary of Oil and Natural Gas Terms

The terms defined in this section are used throughout this prospectus:

Bbl. One stock tank barrel, of 42 U.S. gallons liquid volume, used herein in reference to crude oil, condensate or natural gas liquids.

Bcf. One billion cubic feet of natural gas.

Boe. Barrels of oil equivalent, with six thousand cubic feet of natural gas being equivalent to one barrel of oil.

British thermal unit. The heat required to raise the temperature of a one-pound mass of water from 58.5 to 59.5 degrees Fahrenheit.

Basin. A large natural depression on the earth s surface in which sediments generally brought by water accumulate.

Completion. The process of treating a drilled well followed by the installation of permanent equipment for the production of natural gas or oil, or in the case of a dry hole, the reporting of abandonment to the appropriate agency.

Developed acreage. The number of acres that are allocated or assignable to productive wells or wells capable of production.

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

Dry hole. 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.

Enhanced recovery. The recovery of oil and natural gas through the injection of liquids or gases into the reservoir, supplementing its natural energy. Enhanced recovery methods are often applied when production slows due to depletion of the natural pressure.

Environmental Assessment (EA). An environmental assessment, a study that can be required pursuant to federal law to assess the potential direct, indirect and cumulative impacts of a project.

Environmental Impact Statement (EIS). An environmental impact statement, a more detailed study that can be required pursuant to federal law of the potential direct, indirect and cumulative impacts of a project that may be made available for public review and comment.

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 or stratigraphic condition. The field name refers to the surface area, although it may refer to both the surface and the underground productive formations.

Formation. A layer of rock which has distinct characteristics that differ from nearby rock.

Horizontal drilling. A drilling technique used in certain formations where a well is drilled vertically to a certain depth and then drilled at a right angle within a specified interval.

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Infill wells. Wells drilled into the same pool as known producing wells so that oil or natural gas does not have to travel as far through the formation.

MBbl. One thousand barrels of crude oil, condensate or natural gas liquids.

Mcf. One thousand cubic feet of natural gas.

MMBbl. One million barrels of crude oil, condensate or natural gas liquids.

MMBoe. One million Boe.

MMBtu. One million British thermal units.

MMcf. One million cubic feet of natural gas.

NYMEX. The New York Mercantile Exchange.

Net acres. The percentage of total acres an owner has out of a particular number of acres, or a specified tract. An owner who has 50% interest in 100 acres owns 50 net acres.

Overpressured. A subsurface formation that exerts an abnormally high formation pressure on a wellbore drilled into it.

PUD. Proved undeveloped.

PV-10. When used with respect to oil and natural gas reserves, PV-10 means the estimated future gross revenue to be generated from the production of proved reserves, net of estimated production and future development and abandonment costs, using prices and costs in effect at the determination date, before income taxes, and without giving effect to non-property-related expenses, discounted to a present value using an annual discount rate of 10% in accordance with the guidelines of the SEC. PV-10 is a non-GAAP financial measure. However, our PV-10 and our standardized measure of discounted future net cash flows (the most directly comparable measure calculated and presented in accordance with GAAP) are equivalent because we are a subchapter S-corporation until the closing date of this offering.

Primary recovery. The period of production in which oil moves from its reservoir through the wellbore under naturally occurring reservoir pressure.

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

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

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

Proved undeveloped reserves (PUD). 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.

Recompletion. The process of re-entering an existing wellbore that is either producing or not producing and completing new reservoirs in an attempt to establish or increase existing production.

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

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Spacing. The distance between wells producing from the same reservoir. Spacing is often expressed in terms of acres, e.g., 40-acre spacing, and is often established by regulatory agencies.

Standardized Measure. Discounted future net cash flows estimated by applying year-end prices to the estimated future production of year-end proved reserves. Future cash inflows are reduced by estimated future production and development costs based on period-end costs to determine pre-tax cash inflows. Future income taxes, if applicable, are computed by applying the statutory tax rate to the excess of pre-tax cash inflows over our tax basis in the oil and gas properties. Future net cash inflows after income taxes are discounted using a 10% annual discount rate.

Unit. The joining of all or substantially all interests in a reservoir or field, rather than a single tract, to provide for development and operation without regard to separate property interests. Also, the area covered by a unitization agreement.

Waterflood. The injection of water into an oil reservoir to push additional oil out of the reservoir rock and into the wellbores of producing wells. Typically an enhanced recovery process.

Wellbore. The hole drilled by the bit that is equipped for oil or gas production on a completed well. Also called well or borehole.

Working interest. The right granted to the lessee of a property to explore for and to produce and own oil, gas, or other minerals. The working interest owners bear the exploration, development, and operating costs on either a cash, penalty, or carried basis.

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January 16, 2006

Continental Resources, Inc.

302 North Independence

Enid, Oklahoma 73702

Gentlemen:

At your request we have prepared an estimate of the proved reserves and future production and income attributable to certain leasehold interests of Continental Resources, Inc. as of December 31, 2005. The properties evaluated by Ryder Scott Company, L. P. (Ryder Scott) were selected by Continental Resources, and account for approximately 82.8 percent of the future net income discounted at 10 percent attributable to the proved reserves as of December 31, 2005. The income data have been estimated using the Securities and Exchange Commission (SEC) guidelines for future cost and price parameters.

The estimated reserve quantities and future income quantities presented in this report are related to hydrocarbon prices. December 31, 2005 hydrocarbon prices were used in the preparation of this report; however, actual future prices may vary significantly from December 31, 2005 prices due to a combination of economic and political forces. Therefore, quantities of reserves actually recovered and quantities of income actually received may differ significantly from the estimated quantities presented in this report. The results are summarized as follows:

SEC PARAMETERS

Estimated Proved Net Reserve and Income Data

Certain Leasehold Interests of

Continental Resources, Inc.

As of December 31, 2005

	Net Oil** M Barrels	Net Gas** MMCF	Future Net** Income M$	Discounted** FNI @ 10%M$
	87,506	56,036	$ 3,348,180	$ 1,824,387

Evaluated by Ryder Scott				
Evaluated by Continental Resources	11,139	52,082	$ 741,176	$ 379,988
Total Proved Reserves	98,645	108,118	$ 4,089,356	$ 2,204,375

* Ryder Scott has not reviewed the reserves and cashflow projections for those properties evaluated by Continental Resources, Inc. Ryder Scott has included these values at the request of Continental Resources, Inc. and expresses no opinion as to the reasonableness of these values.

** From TRC Consultants : PhdWin Decline Analysis

Liquid hydrocarbons are expressed in standard 1000 barrels. All gas volumes are sales gas expressed in millions of cubic feet (MMCF) at the official temperature and pressure bases of the areas where the gas reserves are located. No attempt has been made to quantify or otherwise account for any accumulated gas production imbalances that may exist.

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.

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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.

Projection Rates

Initial production rates are based on the current producing rates for those reservoirs now on production. Test data and other related information was 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. The future anticipated 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 projected to commence at an anticipated date of delivery, which was furnished by Continental Resources, Inc.

The future production rates from reservoirs 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

Continental Resources, Inc. has utilized hydrocarbon prices in effect at December 30, 2005, the crude oil price was $61.04 per barrel and the spot gas price was $11.23 per MMBTU. Product prices, which were actually used for each property, reflect adjustment from the above stated prices for gravity, quality, local conditions, and/or distance from market. These prices were held constant to depletion of the properties. In accordance with Securities and Exchange Commission guidelines, changes in hydrocarbon prices subsequent to December 31, 2005 were not considered in this report. Ryder Scott has not performed a detailed study of the product prices and makes no warranty for the product prices utilized in this report.

Costs

Continental Resources, Inc supplied operating costs for the leases and wells in this report. 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. Development costs were furnished by Continental Resources, Inc. and are based on authorizations for expenditure for the proposed work or actual costs for similar projects. The current operating and development costs were held constant throughout the life of the properties. Continental Resources, Inc. has used an estimate of zero abandonment costs after salvage value for all properties in this report. Ryder Scott has not performed a detailed study of the operating and development costs and makes no warranty for the costs utilized in this report.

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General

Ryder Scott Company performed the reserve analysis and generated the projection of future production presented in this report. However, at the request of Continental Resources, Inc., the economic analyses were performed using TRC Consultants PhdWin Decline Analysis. Ryder Scott Company, L. P. has made every attempt to confirm that the values used for scheduling production were correct. However, the internal calculations of this program were accepted without verification. In addition, Ryder Scott Company has accepted the ownership interests; costs and prices supplied by Continental Resources, Inc. as correct and have not attempted to verify those values. Ryder Scott Company has not attempted to verify the accuracy of the economic output from TRC Consultants PhdWin Decline Analysis.

As prepared by Continental Resources, Inc., the tables presented in this report are generated by TRC Consultants PhdWin Decline Analysis and are located behind the Appendix tab. The summary report contains individual tables of estimated production and income by year beginning January 1, 2006 by reserve category for the properties evaluated by Ryder Scott. These tables are located behind the tab titled Grand Summary Projections . A one-line summary of net reserves and income data for each of the subject properties is presented behind the tab titled One-Line Summaries . A one-line summary of reserves and income data ranked by BTAX cashflow discounted at 10 percent is behind the Property Ranking tab.

While it may reasonably be anticipated that the prices received by Continental Resources, Inc. for the sale of its production may be higher or lower than the prices used in this evaluation as described above, and the operating costs relating to such production may also increase above existing levels, such increases or decreases in prices and costs were, in accordance with rules adopted by the SEC, omitted from consideration in making this evaluation.

The reserve estimates presented herein are based upon a detailed study of the top valued properties in which Continental Resources, Inc. owns an interest; however, we have not made any field examination of the properties. Continental Resources, Inc. 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 production data, ownership interests, prices, costs and other factual information furnished to Ryder Scott Company, L. P. by Continental Resources, Inc. in connection with this investigation were accepted without independent verification.

Neither Ryder Scott Company, L. P., nor any of its employees has 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 of Continental Resources, Inc. The data, work papers and maps used in the preparation of 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.

Gary Krieger, P.E.
Senior Vice President

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Shares

Continental Resources, Inc.

Common Stock

PROSPECTUS

JPMorgan

Merrill Lynch & Co.

Citigroup

UBS Investment Bank

Petrie Parkman & Co.

Raymond James

, 2006

You should rely only on the information contained in this prospectus. We have not authorized anyone to provide you with information different from that contained in this prospectus. The selling shareholder is offering to sell, and seeking offers to buy, shares of common stock only in jurisdictions where offers and sales are permitted. The information contained in this prospectus is accurate only as of the date of this prospectus, regardless of the time of delivery of this prospectus or of any sale of our common stock.

No action is being taken in any jurisdiction outside the United States to permit a public offering of the common stock or possession or distribution of this prospectus in that jurisdiction. Persons who come into possession of this prospectus in jurisdictions outside the United States are required to inform themselves about and to observe any restrictions as to this offering and the distribution of this prospectus applicable to that jurisdiction.

Until , 2006, all dealers that buy, sell or trade in our common stock, whether or not participating in this offering, may be required to deliver a prospectus. This is in addition to the dealers obligation to deliver a prospectus when acting as underwriters and with respect to their unsold allotments or subscriptions.

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Part II

Information Not Required in Prospectus

Item 13. Other Expenses of Issuance and Distribution

The following table sets forth the costs and expenses to be paid by us in connection with the sale of the shares of common stock being registered hereby. All amounts are estimates except for the SEC registration fee, the NASD filing fee and the NYSE listing fee.

Securities and Exchange Commission registration fee	$ 61,525
NASD filing fee	58,000
NYSE listing fee	250,000
Accounting fees and expenses	350,000
Legal fees and expenses	650,000
Printing and engraving expenses	225,475
Transfer agent and registrar fees and expenses	5,000
Total	$ 1,600,000

Item 14. Indemnification of Directors and Officers

Continental Resources, Inc. (the Registrant) is incorporated in Oklahoma. Section 1031 of the Oklahoma General Corporation Act (the OGCA) authorizes a court to award, or a corporation s board of directors to grant, indemnity under certain circumstances to directors, officers employees or agents in connection with actions, suits or proceedings, by reason of the fact that the person is or was a director, officer, employee or agent, against expenses and liabilities incurred in such actions, suits or proceedings so long as they acted in good faith and in a manner the person reasonable believed to be in, or not opposed to, the best interests of the company, and with respect to any criminal action if they had no reasonable cause to believe their conduct was unlawful. With respect to suits by or in the right of such corporation, however, indemnification is generally limited to attorneys fees and other expenses and is not available if such person is adjudged to be liable to such corporation unless the court determines that indemnification is appropriate.

In connection with the closing of the offering, the Registrant will amend and restate its certificate of incorporation and bylaws. As permitted by the OGCA, the Registrant s amended and restated certificate of incorporation will include a provision that eliminates the personal liability of its directors to the Registrant or its shareholders for monetary damages for breach of fiduciary duty as a director, except for liability:

for any breach of the director s duty of loyalty to it or its shareholders;

for acts or omissions not in good faith or that involve intentional misconduct or a knowing violation of law;

under section 1053 of the OGCA regarding unlawful dividends and stock purchases; or

for any transaction for which the director derived an improper personal benefit.

As permitted by the OGCA, the Registrant s amended and restated certificate of incorporation will provide that the Registrant is required to indemnify its directors and officers to the fullest extent permitted by the OGCA.

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As permitted by Oklahoma law, the Registrant s amended and restated bylaws will provide that:

- the Registrant may indemnify its other employees and agents, subject to very limited exceptions;

- the Registrant is required to advance expenses (including without limitation, attorneys fees), as incurred, to its directors and officers in connection with a legal proceeding, subject to very limited exceptions; and

- the rights conferred in the Registrant s bylaws are not exclusive.

The indemnification provisions in the Registrant s amended and restated certificate of incorporation may be sufficiently broad to permit indemnification of its directors and officers for liabilities arising under the Securities Act.

Under Oklahoma law, corporations also have the power to purchase and maintain insurance for directors, officers, employees and agents.

Prior to the closing of the offering, it is contemplated that the Registrant and its subsidiaries will obtain liability insurance policies which indemnify their directors and officers against loss arising from claims by reason of their legal liability for acts as such directors and officers, subject to limitations and conditions as set forth in the policies.

The Registrant has entered into written indemnification agreements with all of its directors and executive officers (including each of its named executive officers). These indemnification agreements are intended to permit indemnification to the fullest extent permitted by the OGCA. It is possible that the applicable law could change the degree to which indemnification is expressly permitted.

The indemnification agreements cover expenses (including attorneys fees), judgments, fines and amounts paid in settlement incurred as a result of the fact that such person, in his or her capacity as a director or officer, is made or threatened to be made a party to any suit or proceeding. The indemnification agreements generally cover claims relating to the fact that the indemnified party is or was an officer, director, employee or agent of the Registrant or any of its affiliates, or is or was serving at the Registrant s request in such a position for another entity. The indemnification agreements also obligate the Registrant to promptly advance all reasonable expenses incurred in connection with any claim. The indemnitee is, in turn, obligated to reimburse the Registrant for all amounts so advanced if it is later determined that the indemnitee is not entitled to indemnification. The indemnification provided under the indemnification agreements is not exclusive of any other indemnity rights; however, double payment to the indemnitee is prohibited.

The Registrant will not be obligated to indemnify the indemnitee with respect to claims brought by the indemnitee against it without prior approval of a majority of the Registrant s board of directors, except for claims brought by the Indemnitee to enforce his or her rights under the indemnification agreement.

Under the underwriting agreement that the Registrant will enter into in connection with the offering, the underwriters will be obligated, under certain circumstances, to indemnify directors and officers of the registrant against certain liabilities, including liabilities under the Securities Act. Reference is made to the form of underwriting agreement filed as Exhibit 1.1 hereto.

The foregoing discussion of the Registrant s amended and restated certificate of incorporation and bylaws and Oklahoma law is not intended to be exhaustive and is qualified in its entirety by such certificate of incorporation, bylaws or law.

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Item 15. Recent Sales of Unregistered Securities

During the past three years, the Registrant has issued unregistered securities to a limited number of persons, as described below. None of these transactions involved any underwriters or public offerings, and the Registrant believes that each of these transactions was exempt from registration requirements pursuant to Rule 701 of the Securities Act. The recipients of these securities represented their intention to acquire the securities for investment only and not with a view to or for sale in connection with any distribution thereof, and appropriate legends were affixed to the share certificates and instruments issued in these transactions.

During the year ended December 31, 2005, the Registrant issued options to purchase an aggregate of 275,000 shares of its common stock to certain of its executive officers under the Continental Resources, Inc. 2000 Stock Option Plan. During the year ended December 31, 2004, the Registrant issued options to purchase an aggregate of 220,000 shares of its common stock to certain of its executive officers under the Continental Resources, Inc. 2000 Stock Option Plan. The Registrant issued no options to purchase shares of its common stock under the Continental Resources, Inc. 2000 Stock Option Plan in 2003 or 2006.

During the year ended December 31, 2005 and during 2006, the Registrant also issued 990,517 and 200,772 shares, respectively, of its restricted stock to certain of its executive officers, employees and directors under the Continental Resources, Inc. 2005 Long-Term Incentive Plan.

Item 16. Exhibits and Financial Statement Schedules

(a) The following exhibits are filed herewith:

Number	Exhibit
1.1**	Form of Underwriting Agreement.
3.1**	Form of Third Amended and Restated Certificate of Incorporation of Continental Resources, Inc.
3.2**	Form of Second Amended and Restated Bylaws of Continental Resources, Inc.
4.1**	Specimen Common Stock Certificate.
4.2**	Form of Registration Rights Agreement by and among Continental Resources, Inc., the Revocable Inter Vivos Trust of Harold G. Hamm, the Harold Hamm DST Trust and the Harold Hamm HJ Trust.
5.1***	Opinion of Crowe & Dunlevy, A Professional Corporation.
10.1**	Sixth Amended and Restated Credit Agreement among Union Bank of California, N.A., Guaranty Bank, FSB, Fortis Capital Corp., The Royal Bank of Scotland plc, other financial institutions and banks and Continental Resources, Inc. dated April 12, 2006.
10.2	Omnibus Agreement among Continental Resources, Inc., Hiland Partners, LLC, Harold Hamm, Hiland Partners GP, LLC, Continental Gas Holdings, Inc. and Hiland Partners, LP effective as of the closing of Hiland Partners, LP s initial public offering of common units (incorporated by reference to Exhibit 10.10 to the Annual Report on Form 10-K of Hiland Partners, LP filed on March 30, 2005, Commission File No. 000-51120).
10.3	Compression Services Agreement among Hiland Partners, LP and Continental Resources, Inc. effective as of January 28, 2005 (incorporated by reference to Exhibit 10.3 to the Annual Report on Form 10-K of Hiland Partners, LP filed on March

	30, 2005, Commission File No. 000-51120).
10.4	Gas Purchase Contract between Continental Resources, Inc. and Hiland Partners, LP November 8, 2005 (incorporated by reference to Exhibit 10.1 to the Current Report on Form 8-K of Hiland Partners, LP filed on November 10, 2005, Commission File No. 000-51120).

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Number	Exhibit
10.5	Strategic Customer Relationship Agreement among Complete Energy Services, Inc., CES Mid-Continent Hamm, Inc. and Continental Resources, Inc. dated October 14, 2004 (incorporated by reference to Exhibit 10.12 to the Registration Statement on Form S-1 of Complete Production Services, Inc. filed on November 15, 2005, Commission File No. 333-128750).
10.6**	Continental Resources, Inc. 2000 Stock Option Plan.
10.7**	First Amendment to Continental Resources, Inc. 2000 Stock Option Plan.
10.8**	Form of Incentive Stock Option Agreement.
10.9**	Amended and Restated Continental Resources, Inc. 2005 Long-Term Incentive Plan effective as of April 3, 2006.
10.10**	Form of Restricted Stock Award Agreement.
10.11**	Amended and Restated Employment Agreement between Continental Resources, Inc. and Mark E. Monroe dated April 3, 2006.
10.12**	Form of Indemnification Agreement between Continental Resources, Inc. and each of the directors and executive officers thereof.
10.13**	Membership Interest Assignment Agreement by and between Continental Resources, Inc., the Harold Hamm Revocable Inter Vivos Trust, the Harold Hamm HJ Trust and the Harold Hamm DST Trust dated March 30, 2006.
21.1*	Subsidiaries of Continental Resources, Inc. (updating Exhibit 21.1 to Amendment No. 1 to the Registration Statement on Form S-1 of Continental Resources, Inc. filed on April 14, 2006, Commission File No. 333-132257).
23.1*	Consent of Grant Thornton LLP.
23.2*	Consent of Ernst & Young LLP.
23.3*	Consent of Ryder Scott Company, L.P.
23.4***	Consent of Crowe & Dunlevy, A Professional Corporation (included in Exhibit 5.1).
23.5**	Consent of Vinson & Elkins L.L.P.
24.1**	Power of Attorney.

* Filed herewith.
** Previously filed.
*** To be filed by amendment.

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Item 17. Undertakings

The undersigned Registrant hereby undertakes to provide to the underwriters at the closing specified in the underwriting agreement certificates in such denominations and registered in such names as required by the underwriters to permit prompt delivery to each purchaser.

Insofar as indemnification for liabilities arising under the Securities Act may be permitted to directors, officers and controlling persons of the Registrant pursuant to the provisions described in Item 14 above, or otherwise, the Registrant has been advised that in the opinion of the Securities and Exchange Commission such indemnification is against public policy as expressed in the Securities Act and is, therefore, unenforceable. In the event that a claim for indemnification against such liabilities (other than the payment by the Registrant of expenses incurred or paid by a director, officer or controlling person of the Registrant 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 hereunder, the Registrant 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 Securities Act and will be governed by the final adjudication of such issue.

The undersigned Registrant hereby undertakes that:

(1) For purposes of determining any liability under the Securities Act, 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 497(h) under the Securities Act shall be deemed to be part of this Registration Statement as of the time it was declared effective; and

(2) For the purpose of determining any liability under the Securities Act, 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 the 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 has duly caused this Amendment No. 4 to Registration Statement on Form S-1 to be signed on its behalf by the undersigned, thereunto duly authorized, in Enid, Oklahoma, on this 17th day of November, 2006.

CONTINENTAL RESOURCES, INC.

By: /s/ Mark E. Monroe

Name: **Mark E. Monroe**
Title: **President and Chief Operating Officer**

Pursuant to the requirements of the Securities Act of 1933, this Amendment No. 4 to Registration Statement on Form S-1 has been signed by the following persons in the capacities and on the dates indicated.

Signature	Title	Date
* **Harold G. Hamm**	Chairman, Chief Executive Officer and Director (principal executive officer)	November 17, 2006
/s/ Mark E. Monroe **Mark E. Monroe**	President, Chief Operating Officer and Director	November 17, 2006
* **John D. Hart**	Vice President, Chief Financial Officer and Treasurer (principal financial and accounting officer)	November 17, 2006
* **Jack H. Stark**	Senior Vice President Exploration and Director	November 17, 2006

*		
Robert J. Grant	Director	November 17, 2006
*		
George S. Littell	Director	November 17, 2006
*		
Lon McCain	Director	November 17, 2006
*		
H. R. Sanders, Jr.	Director	November 17, 2006

*By: /s/ Mark E. Monroe

Mark E. Monroe

Attorney-in-Fact

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23.2*	Consent of Ernst & Young LLP.
23.3*	Consent of Ryder Scott Company, L.P.
23.4***	Consent of Crowe & Dunlevy, A Professional Corporation (included in Exhibit 5.1).
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* Filed herewith.
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