CONTINENTAL RESOURCES INC
Form S-1
March 07, 2006

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As filed with the Securities and Exchange Commission on March 7, 2006

Registration No. 333-

SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

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

Vinson & Elkins L.L.P.

1001 Fannin, Suite 2300

Houston, Texas 77002-6760

(713) 758-2222

Winthrop B. Conrad, Jr.

Davis Polk & Wardwell

450 Lexington Avenue

New York, New York 10017

(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. ¨

CALCULATION OF REGISTRATION FEE

Title of Each Class of Securities to be Registered	Proposed Maximum Aggregate Offering Price	Amount of Registration Fee
Common stock, par value $.01	$ 575,000,000(1)(2)	$ 61,525

(1) Includes common stock issuable upon exercise of the underwriters option to purchase additional shares of common stock.
(2) Estimated solely for the purpose of calculating the registration fee pursuant to Rule 457(o).

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 March 7, 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. We intend to apply for listing of our common stock on the New York Stock Exchange 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.

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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[Map of Continental Resources, Inc. s areas of operations, including proved reserves per region, fourth quarter 2005 production, acreage and scheduled drilling locations.]

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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 identify 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 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. These drillbit proved reserve additions replaced 309% of production during that period at an average drillbit finding cost of $5.89 per Boe.

As of December 31, 2005, our estimated proved reserves were 116.7 MMBoe, with a PV-10 of $2.2 billion. Our PV-10 and standardized measure of discounted future net cash flows are equivalent because we are a subchapter S-corporation. Estimated proved developed reserves were 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, we generated revenues of $375.8 million and operating cash flows of $265.3 million.

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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 then ended 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 (in millions)	Net producing wells	Fourth quarter 2005 (Boe per day)	Percent of total	Annualized reserve/ production index(1)
Rocky Mountain:							
Red River units	67,711	58%	$ 1,215	187	9,792	44%	18.9
Bakken field	23,878	21%	501	34	5,999	27%	10.9
Other	9,228	8%	141	230	1,694	8%	14.9
Mid-Continent	15,472	13%	328	630	3,715	17%	11.4
Gulf Coast	376		19	23	973	4%	1.1
Total	116,665	100%	$ 2,204	1,104	22,173	100%	14.4

(1) 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 fourth quarter 2005 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				
	Gross	Net	Gross	Net	Scheduled drilling locations(1)	Wells planned for drilling	Capital expenditures (in millions)
Rocky Mountain:							
Red River units	144,176	128,047			135	41	$ 84
Bakken field	52,421	38,971	588,081	356,426	918	54	96
Other	45,720	36,153	358,649	208,612	71	34	40
Mid-Continent	152,734	99,279	115,746	73,582	96	70	64
Gulf Coast	41,842	11,890	23,598	7,873	13	13	17

Total	436,893	314,340	1,086,074	646,493	1,233	212	$ 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, 256 are classified as PUDs. As of March 1, 2006, we have commenced drilling of 27 locations shown in the table, including 15 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 own 168,000 gross (72,000 net) undeveloped acres in these projects, 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 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. These drillbit proved reserve additions replaced 309% of production during that five-year period and 450% of production during 2005 at an average drillbit finding cost of $5.89 and $4.37 per Boe, respectively.

Internally generate prospects. Our technical staff internally generates substantially all of the opportunities for the investment of our capital. Because we are typically an early entrant in new or emerging plays, our costs to acquire undeveloped acreage are generally 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 and Bakken 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 71% of our total oil and natural gas production during the three months ended December 31, 2005.

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.

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 and have the potential to make the Bakken field one of our largest sources of growth of reserves and production over the next several years.

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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 are currently drilling a horizontal test well and 12,000 undeveloped net acres in Saskatchewan, Canada on which we plan to drill a horizontal test well in 2006.

Within the Red River units, we plan to drill 131 horizontal wells and 61 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 significantly 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 December 31, 2005, production in the Red River units averaged approximately 9,792 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 39 waterflood units. Additionally, we operate eight of the eleven 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. Our drillbit finding costs were $4.37 per Boe and $5.89 per Boe over the one- and five-year periods ending December 31, 2005, respectively.

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 eight senior officers have an average of 25 years of oil and gas industry experience. Additionally, our technical staff, which includes 21 petroleum engineers, 14 geoscientists and seven landmen, has an average of more than 19 years experience in the industry.

Strong financial position. As of December 31, 2005, we had outstanding borrowings under our credit facility of approximately $143.0 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 any hedges in place.

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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 13 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.

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.

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

Common stock to be owned by the selling shareholder after the offering: shares

Common stock to be outstanding after the offering: 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 a for stock split of our shares of common stock to be effected in the form of a stock dividend prior to the consummation of this offering;
- assumes no exercise of the underwriters option to purchase additional shares; and
- assumes an initial public offering price of $, which is the mid-point 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, 2001 through 2005, has been derived from our annual historical consolidated financial statements. 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 audited 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.

The share and per share information presented below does not give effect to the for stock split to be effected in the form of a stock dividend prior to the closing of this offering:

	Year ended December 31,				
(in thousands, except per share amounts)	**2001**	**2002**	**2003**	**2004**	**2005**
Statement of operations data:					
Revenues:					
Oil and natural gas sales	$ 112,170	$ 108,752	$ 138,948	$ 181,435	$ 361,833
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
Total revenues	364,089	266,583	317,609	418,910	375,764
Operating costs and expenses:					
Production expense	31,859	32,299	40,821	43,754	52,754
Production tax	8,385	7,729	10,251	12,297	16,031
Exploration expense	15,863	10,229	17,221	12,633	5,231
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
Depreciation, depletion, amortization and accretion	25,659	29,010	40,256	38,627	49,802
Property impairments	10,113	25,686	8,975	11,747	6,930
General and administrative	6,199	8,489	9,407	10,390	17,551
Equity compensation(2)		179	197	2,010	13,715
(Gain) loss on sale	(3,423)	(223)	(589)	150	(3,026)
Total operating costs and expenses	$ 342,478	$ 269,601	$ 298,911	$ 365,284	$ 166,965

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	Year ended December 31,				
(in thousands, except per share amounts)	**2001**	**2002**	**2003**	**2004**	**2005**
Income (loss) from operations	$ 21,611	$ (3,018)	$ 18,698	$ 53,626	$ 208,799
Other income (expense)					
Interest expense	(15,324)	(18,216)	(19,761)	(23,617)	(14,220)
Loss on redemption on bonds				(4,083)	
Other	645	912	295	890	867
Total other income (expense)	(14,679)	(17,304)	(19,466)	(26,810)	(13,353)
Income (loss) from continuing operations before income taxes	6,932	(20,322)	(768)	26,816	195,446
Provision for income taxes(3)					1,139
Income (loss) from continuing operations	6,932	(20,322)	(768)	26,816	194,307
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
Cumulative effect of change in accounting principle(5)			2,162		
Net income (loss)	$ 11,667	$ (20,032)	$ 2,340	$ 27,864	$ 194,307
Basic earnings (loss) per share:					
From continuing operations	$ 0.48	$ (1.41)	$ (0.05)	$ 1.87	$ 13.52
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
Cumulative effect of change in accounting principle			0.15		
Net income (loss) per share	$ 0.81	$ (1.39)	$ 0.16	$ 1.94	$ 13.52
Shares used in basic earnings (loss) per share	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
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
Cumulative effect of accounting change			0.15		
Net income (loss) per share	$ 0.81	$ (1.39)	$ 0.16	$ 1.93	$ 13.42
Shares used in diluted earnings (loss) per share	14,393	14,369	14,369	14,476	14,482

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(in thousands, except per share amounts)	Year ended December 31, 2001	2002	2003	2004	2005
Pro forma C-corporation data:					
Income (loss) from continuing operations before income taxes	$ 6,932	$ (20,322)	$ (768)	$ 26,816	$ 195,446
Pro forma provision (benefit) for income taxes attributable to operations	2,634	(7,722)	(292)	10,190	74,269
Pro forma income (loss) from operations after tax	4,298	(12,600)	(476)	16,626	121,177
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 principal net of tax			1,340		
Pro forma net income (loss)	$ 7,234	$ (12,420)	$ 1,451	$ 17,276	$ 121,177
Pro forma net income (loss) per basic share	$ 0.50	$ (0.86)	$ 0.10	$ 1.20	$ 8.43
Pro forma net income (loss) per diluted share	0.50	(0.86)	0.10	1.19	8.37
Other financial data:					
Cash dividends per share	$	$	$	$ 1.04	$ 0.14
EBITDAX (6)	78,626	63,288	88,750	116,498	285,344
Net cash provided by operations	63,413	46,997	65,246	93,854	265,265
Net cash used in investing	(106,384)	(113,295)	(108,791)	(72,992)	(113,600)
Net cash provided by (used in) financing	43,045	61,593	43,302	(7,245)	(141,467)
Capital expenditures	111,023	113,447	114,145	94,307	144,800
Balance sheet data (at period end):					
Cash and cash equivalents	$ 7,225	$ 2,520	$ 2,277	$ 15,894	$ 6,014
Property and equipment, net	317,331	367,903	439,432	434,339	509,393
Total assets	354,485	406,677	484,988	504,951	600,234
Long-term debt, including current maturities	183,395	247,105	290,920	290,522	143,000
Shareholders equity	135,113	115,081	116,932	130,385	324,730

(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 accounted for stock-based compensation under Accounting Principles Board Opinion No. 25, Accounting for Stock Issued to Employees using the intrinsic method. Our stock based compensation plan requires us to purchase vested shares at the employee s request based on an internally calculated fair-market value of our stock. Amounts in this caption represent

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the increase in our liability associated with our purchase obligation. The fair market 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 if we begin reporting under Section 12 of the Securities Exchange Act of 1934, as amended.

(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 difference between the conversion date fair market value and 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.

(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 EBITDA ratio of no greater than 3.75 to 1 on a rolling four-quarter basis. Our credit facility defines EBITDA consistently with the definition of EBITDAX utilized and presented by us. At December 31, 2005, this ratio was approximately 0.5 to 1. The following table represents a reconciliation of our net income (loss) to EBITDAX:

	Year ended December 31,				
(in thousands)	**2001**	**2002**	**2003**	**2004**	**2005**
Net income (loss)	$ 11,667	$ (20,032)	$ 2,340	$ 27,864	$ 194,307
Interest expense	15,324	18,216	19,761	23,617	14,220
Provision for income taxes					1,139
Depreciation, depletion, amortization and accretion	25,659	29,010	40,256	38,627	49,802
Property impairments	10,113	25,686	8,975	11,747	6,930
Exploration expense	15,863	10,229	17,221	12,633	5,231
Equity compensation		179	197	2,010	13,715
EBITDAX	$ 78,626	$ 63,288	$ 88,750	$ 116,498	$ 285,344

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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)	$ 815	$ 1,114	$ 2,204
Estimated reserve life (in years)(1)	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
Annual drillbit reserve replacement percentage(2)	284%	155%	450%
Three-year average drillbit finding cost ($/Boe)			$ 6.01

(1) Calculated by dividing proved reserves by production volumes for the year indicated.

(2) Calculated by dividing reserve additions from extensions and discoveries by the production for the corresponding period.

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,		
	2003	**2004**	**2005**

Net production volumes:			
Oil (MBbls)	3,463	3,688	5,708
Natural gas (MMcf)	10,751	8,794	9,006
Oil equivalents (MBoe)	5,255	5,154	7,209
Average prices:			
Oil, without hedges ($/Bbl)	$ 28.88	$ 38.85	$ 52.45
Oil, with hedges ($/Bbl)	25.98	37.12	52.45
Natural gas ($/Mcf)	4.55	5.06	6.93
Oil equivalents, without hedges ($/Bbl)	28.35	36.45	50.19
Oil equivalents, with hedges ($/Bbl)	26.44	35.20	50.19
Costs and expenses:			
Production expense ($/Boe)	$ 7.77	$ 8.49	$ 7.32
Production tax ($/Boe)	1.95	2.39	2.22
General and administrative ($/Boe)	1.79	2.02	2.43
DD&A expense ($/Boe)	7.10	7.02	6.50

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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;
- 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.

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 success 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

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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.

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.

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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.

The results of enhanced recovery methods are uncertain.

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.

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

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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.

A substantial portion of our producing properties are located in the Rocky Mountain region, making us vulnerable to risks associated with operating in one major geographic area.

Our producing properties are geographically concentrated in the Rocky Mountain region. In particular, a substantial portion of our proved reserves are located in the Red River units and in the Bakken field. At December 31, 2005, the Red River units and the Bakken field represented approximately 55% and 23% of our PV-10, respectively. As a result of this concentration, we may be disproportionately exposed to the impact of delays or interruptions of production from these wells caused by significant governmental regulation, transportation capacity constraints, curtailment of production or interruption of transportation of oil produced from the wells in these areas.

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.

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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 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 and explosions;
- 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.

We describe some of our current prospects and our plans to explore those prospects in this prospectus. 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

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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 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 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

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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 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.

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. 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.

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

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,

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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 three largest purchasers of our oil and natural gas in 2005 accounted for 31% , 19% and 10% 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, representing approximately % of

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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 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 pro forma as adjusted net tangible book value per share of common stock from the initial public offering price, and our pro forma as adjusted net tangible book value as of December 31, 2005 after giving effect to this offering would be $ 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

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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.

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 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 have declared a cash dividend of approximately $60.0 million payable to our shareholders for tax purposes and, subject to forfeiture, to holders of unvested restricted stock in April 2006, 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. In addition, our credit facility prohibits us from paying dividends other than for tax purposes.

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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.

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 by-laws 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 by-laws 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 and commissions. We will pay all expenses relating to the selling shareholder s sale of common stock in this offering, other than underwriting discounts and commissions. If the underwriters option to purchase additional shares is exercised in full, we estimate that the selling shareholder s net proceeds will be approximately $ million.

Dividend policy

Our credit facility prohibits us from paying dividends other than for tax purposes. As permitted by our credit facility, we have declared a cash dividend of approximately $60.0 million payable to our shareholders for tax purposes and, subject to forfeiture, to holders of unvested restricted stock in April 2006. 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 December 31, 2005:

- on a historical basis, including the effect of a for stock split to be effected as a stock dividend prior to the consummation of this offering; 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 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 December 31, 2005	
(in thousands)	**Historical**	**Pro forma**
Cash and cash equivalents	$ 6,014	$ 6,014
Long-term debt, including current maturities(1)	143,000	143,000
Shareholders equity:		
Common stock, $.01 par value; 20,000,000 shares authorized, 14,458,966 shares issued and outstanding actual and pro forma	144	144
Additional paid-in capital(2)	27,087	152,758
Retained earnings(1)(2)(3)	297,461	65,140
Accumulated other comprehensive loss, net of taxes	38	38
Total shareholders equity	324,730	218,080
Total capitalization	$ 467,730	$ 361,080

(1) We have declared a cash dividend of approximately $60.0 million payable to our shareholders for tax purposes and, subject to forfeiture, to holders of unvested restricted stock in April 2006. The payment of this dividend has not been included in retained earnings or long-term debt.

(2) Pro forma adjustments reflect reclassification of the liability for equity compensation of $12.2 million to additional paid-in capital, expensing offering costs of approximately $1.4 million, a charge to operations of approximately $117.4 million to recognize deferred taxes upon our conversion from a non-taxable subchapter S-corporation to a taxable subchapter C-corporation 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 increment between the fair market 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.

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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. On a pro forma basis as of December 31, 2005, after giving effect to estimated offering expenses, our net tangible book value was $ million, or $ 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 December 31, 2005	$	
Decrease per share attributable to the offering	$	
Pro forma net tangible book value per share after the offering		$
Dilution in pro forma as adjusted net tangible book value per share to new investors		$

The following table sets forth, as of , 2006, the number of shares of common stock and the total consideration and average price per share paid by existing shareholders and by the new investors before deducting offering expenses:

	Shares acquired		Total consideration		Average price paid
	Number	Percent	Amount	Percent	per share
Existing shareholders			$ 27,231,000		
New investors					
Total					

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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 annual historical consolidated financial statements. 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 audited 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.

The share and per share information presented below does not give effect to the for stock split to be effected in the form of a stock dividend prior to the closing of this offering:

	Year ended December 31,				
(in thousands, except per share amounts)	**2001**	**2002**	**2003**	**2004**	**2005**
Statement of operations data:					
Revenues:					
Oil and natural gas sales	$ 112,170	$ 108,752	$ 138,948	$ 181,435	$ 361,833
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
Total revenues	364,089	266,583	317,609	418,910	375,764
Operating costs and expenses:					
Production expense	31,859	32,299	40,821	43,754	52,754
Production tax	8,385	7,729	10,251	12,297	16,031
Exploration expense	15,863	10,229	17,221	12,633	5,231
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
Depreciation, depletion, amortization and accretion	25,659	29,010	40,256	38,627	49,802
Property impairments	10,113	25,686	8,975	11,747	6,930
General and administrative	6,199	8,489	9,407	10,390	17,551
Equity compensation(2)		179	197	2,010	13,715
(Gain) loss on sale	(3,423)	(223)	(589)	150	(3,026)

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

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(in thousands, except per share amounts)	Year ended December 31, 2001	2002	2003	2004	2005
Income (loss) from operations	$ 21,611	$ (3,018)	$ 18,698	$ 53,626	$ 208,799
Other income (expense)					
Interest expense	(15,324)	(18,216)	(19,761)	(23,617)	(14,220)
Loss on redemption on bonds				(4,083)	
Other	645	912	295	890	867
Total other income (expense)	(14,679)	(17,304)	(19,466)	(26,810)	(13,353)
Income (loss) from continuing operations before income taxes	6,932	(20,322)	(768)	26,816	195,446
Provision for income taxes(3)					1,139
Income (loss) from continuing operations	6,932	(20,322)	(768)	26,816	194,307
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
Cumulative effect of change in accounting principle(5)			2,162		
Net income (loss)	$ 11,667	$ (20,032)	$ 2,340	$ 27,864	$ 194,307
Basic earnings (loss) per share:					
From continuing operations	$ 0.48	$ (1.41)	$ (0.05)	$ 1.87	$ 13.52
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
Cumulative effect of change in accounting principle			0.15		
Net income (loss) per share	$ 0.81	$ (1.39)	$ 0.16	$ 1.94	$ 13.52
Shares used in basic earnings (loss) per share	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
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
Cumulative effect of accounting change			0.15		
Net income (loss) per share	$ 0.81	$ (1.39)	$ 0.16	$ 1.93	$ 13.42
Shares used in diluted earnings (loss) per share	14,393	14,369	14,369	14,476	14,482

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(in thousands, except per share amounts)	Year ended December 31, 2001	2002	2003	2004	2005
Pro forma C-corporation data:					
Income (loss) from continuing operations before income taxes	$ 6,932	$ (20,322)	$ (768)	$ 26,816	$ 195,446
Pro forma provision (benefit) for income taxes attributable to operations	2,634	(7,722)	(292)	10,190	74,269
Pro forma income (loss) from operations after tax	4,298	(12,600)	(476)	16,626	121,177
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 principal net of tax			1,340		
Pro forma net income (loss)	$ 7,234	$ (12,420)	$ 1,451	$ 17,276	$ 121,177
Pro forma net income (loss) per basic share	$ 0.50	$ (0.86)	$ 0.10	$ 1.20	$ 8.43
Pro forma net income (loss) per diluted share	0.50	(0.86)	0.10	1.19	8.37
Other financial data:					
Cash dividends per share:	$	$	$	$ 1.04	$ 0.14
EBITDAX (6)	78,626	63,288	88,750	116,498	285,344
Net cash provided by operations	63,413	46,997	65,246	93,854	265,265
Net cash used in investing	(106,384)	(113,295)	(108,791)	(72,992)	(113,600)
Net cash provided by (used in) financing	43,045	61,593	43,302	(7,245)	(141,467)
Capital expenditures	111,023	113,447	114,145	94,307	144,800
Balance sheet data (at period end):					
Cash and cash equivalents	$ 7,225	$ 2,520	$ 2,277	$ 15,894	$ 6,014
Property and equipment, net	317,331	367,903	439,432	434,339	509,393
Total assets	354,485	406,677	484,988	504,951	600,234
Long-term debt, including current maturities	183,395	247,105	290,920	290,522	143,000
Shareholders equity	135,113	115,081	116,932	130,385	324,730

(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 accounted for stock-based compensation under Accounting Principles Board Opinion No. 25, Accounting for Stock Issued to Employees using the intrinsic method. Our stock based compensation plan requires us to purchase vested shares at the employee s request based on an internally calculated fair-market value of our stock. Amounts in this caption represent the increase in our liability associated with our purchase obligation. The fair market 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 if we begin reporting under Section 12 of the Securities Exchange Act of 1934, as amended.

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(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 difference between the conversion date fair market value and 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.

(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 EBITDA ratio of no greater than 3.75 to 1 on a rolling four-quarter basis. Our credit facility defines EBITDA consistently with the definition of EBITDAX utilized and presented by us. At December 31, 2005, this ratio was approximately 0.5 to 1. The following table represents a reconciliation of our net income (loss) to EBITDAX:

	Year ended December 31,				
(in thousands)	**2001**	**2002**	**2003**	**2004**	**2005**
Net income (loss)	$ 11,667	$ (20,032)	$ 2,340	$ 27,864	$ 194,307
Interest expense	15,324	18,216	19,761	23,617	14,220
Provision for income taxes					1,139
Depreciation, depletion, amortization and accretion	25,659	29,010	40,256	38,627	49,802
Property impairments	10,113	25,686	8,975	11,747	6,930
Exploration expense	15,863	10,229	17,221	12,633	5,231
Equity compensation		179	197	2,010	13,715
EBITDAX	$ 78,626	$ 63,288	$ 88,750	$ 116,498	$ 285,344

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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 are generally 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.

Our results of operations are determined primarily by three variables: (1) the volumes of oil and natural gas produced, (2) the prices realized for oil and natural gas sales, and (3) the success of our exploration and development drilling efforts. These performance measures, among others, are discussed below under How we evaluate our operations.

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;

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(4) Reserve replacement ratio, finding cost and PV-10; and

(5) EBITDAX.

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:

				Three-year period	
	2003	2004	2005	Volume increase (decrease)	Percent increase (decrease)
MBbls	3,463	3,688	5,708	2,245	65%
MMcf	10,751	8,794	9,006	(1,745)	(16%)
MBoe	5,255	5,154	7,209	1,954	37%

The increase in our production has been the result of a favorable response to 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, inclusive and exclusive of the effects of hedging, and the differences for each of the three years ended December 31, 2005. 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:

	2003	2004	2005
NYMEX oil price ($/Bbl)	$ 31.08	$ 41.95	$ 57.69
Realized oil price before hedging ($/Bbl)	28.88	38.85	52.45
Difference	$ 2.20	$ 3.10	$ 5.24
NYMEX natural gas price ($/Mcf)	5.33	6.10	8.54
Realized natural gas price ($/Mcf)	4.55	5.06	6.93
Difference	$ 0.78	$ 1.04	$ 1.61

The differences are subject to variability due to quality and location pricing fluctuations caused by localized supply and demand fundamentals and transportation availability. In January 2006,

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the difference between the NYMEX oil price and our realized oil price was approximately $8 per Bbl and indications are that the difference may be between $10 and $11 per Bbl for February 2006. Factors affecting the difference include higher oil 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 historical 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. 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.

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 any hedges in place.

Volumetric operating and administrative costs

Two other measures that we monitor and analyze are production expense per Boe produced and general and administrative expense per Boe produced. 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 per Boe produced for each of the three years ended December 31, 2005:

	2003	2004	2005
Production expense ($/Boe)	$ 7.77	$ 8.49	$ 7.32
General and administrative expense ($/Boe)	1.79	2.02	2.43

Our per unit production expense increased during 2003 and 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 is now declining as we are experiencing higher production volumes due to continued drilling and favorable response to 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. General and administrative expense per Boe was $2.43 in 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.

Reserve replacement ratio, finding cost and PV-10

Reserve replacement ratio, finding cost and PV-10 are three key measures against which we evaluate ourselves. Due to the depleting nature of oil and natural gas reserves, we seek to replace reserves produced and to grow our proved reserve quantity and value.

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The following table presents our reserve replacement ratio and finding cost for each of the three years ended December 31, 2005 and the PV-10 as of the end of each year:

	2003	2004	2005
Reserve replacement ratio from all sources	288%	227%	478%
Reserve replacement ratio from extensions and discoveries	284%	155%	450%
Finding cost per Boe using all sources	$ 6.34	$ 8.25	$ 4.18
Drillbit finding cost ($/Boe)	6.41	11.93	4.37
PV-10 (in millions)	815	1,114	2,204

Finding and developing oil and natural gas reserves economically is critical to our success. The reserve replacement ratio from all sources measures the degree to which we were able to replace production through exploration and development activities, revisions and proved reserve purchases. The finding cost per Boe using all sources was determined by dividing the costs incurred in proved and unproved property acquisitions and in exploration and development activities by the proved reserve Boe additions from extensions and discoveries, revisions and proved reserve purchases. The reserve replacement ratio from extensions and discoveries measures our ability to replace production through exploration and development activities.

Finding cost is a key metric that we utilize to evaluate the cost of additions to our reserve base. We believe we have been able to more effectively control the cost and timing of exploration and development of our properties, including the methods used, due to the high percentage of properties that we operate.

Ryder Scott Company, L.P. (Ryder Scott), our independent petroleum engineers, prepared an estimate of proved reserves for properties comprising approximately 83% of our PV-10 as of December 31, 2003, 2004 and 2005. Our technical staff evaluated the remaining properties. PV-10 is a valuation measure that is sensitive to changes in market prices. 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. As a Subchapter S-corporation, we are not subject to federal or state corporate income taxes on our operating earnings because taxable income is passed through to our shareholders. As a result, our PV-10 and standardized measure of discounted future net cash flows are equivalent.

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 other 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.

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The following table presents our EBITDAX for each of the three years ended December 31, 2005 (in thousands):

	2003	2004	2005
EBITDAX	$ 88,750	$ 116,498	$ 285,344

EBITDAX is a financial measure that is reported to our lenders each calendar quarter. Our credit facility requires that our total debt to EBITDA 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. Our credit facility defines EBITDA 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 consolidated financial data.

Recent events

Our board of directors met on February 28, 2006 and declared the payment of a dividend of approximately $60.0 million ($ per share) for tax purposes to our existing shareholders and, subject to forfeiture, to holders of unvested restricted stock. This dividend will be paid on or about April 13, 2006.

Recognition of deferred taxes upon conversion to a subchapter C-corporation

Concurrent with the completion of this offering, we will convert from a subchapter S-corporation to a subchapter C-corporation. In connection with this conversion, a charge to earnings estimated to be approximately $117 million as of December 31, 2005 will be recorded to recognize deferred taxes.

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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:

	Year ended December 31,		
(in thousands, except price data)	**2003**	**2004**	**2005**
Oil and natural gas sales	$ 138,948	$ 181,435	$ 361,833
Total revenues(1)	317,609	418,910	375,764
Operating costs and expenses(1)	298,911	365,284	166,965
Other income (expense)	(19,466)	(26,810)	(13,353)
Income (loss) from continuing operations before income taxes	(768)	26,816	195,446
Provision for income taxes			(1,139)
Income (loss) from continuing operations	(768)	26,816	194,307
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
Production volumes:			
Oil (MBbl)	3,463	3,688	5,708
Natural gas (MMcf)	10,751	8,794	9,006
Oil equivalents (MBoe)	5,255	5,154	7,209
Average prices:			
Oil, without hedges ($/Bbl)	$ 28.88	$ 38.85	$ 52.45
Oil, with hedges ($/Bbl)	25.98	37.12	52.45
Natural gas ($/Mcf)	4.55	5.06	6.93
Oil equivalents, without hedges ($/Boe)	28.35	36.45	50.19
Oil equivalents, with hedges ($/Boe)	26.44	35.20	50.19

(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.

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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.

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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 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 production basis, production expense and production tax were as follows:

	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.

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Depreciation, depletion, amortization and accretion. The depreciation, depletion and amortization (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 at a drillbit finding cost of $4.37 per Boe 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 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 was $2.02 per Boe and $2.43 per Boe for the years ended December 31, 2004 and 2005, respectively.

Equity compensation. We have granted stock options and restricted stock 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 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

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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 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.

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

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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.

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 production 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%

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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 $1.0 million to $10.4 million was the result of higher wages and other employee-related expenses of $0.6 million. Our general and administrative expense was $1.79 per Boe and $2.02 per Boe for the years ended December 31, 2003 and 2004, respectively.

Equity compensation. 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 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 fair market 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.

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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 both our short-term working capital requirements and our 2006 capital budget. Our board of directors declared a $60.0 million dividend on February 28, 2006 to be paid to our existing shareholders and, subject to forfeiture, to holders of unvested restricted stock.

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, respectively. At December 31, 2005, we had cash and cash equivalents of $6.0 million and available borrowing capacity on our credit facility of $107.0 million. The increase in operating cash flows in 2005 was 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.

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, in our capital program, inclusive of dry hole and seismic costs. The increase in our capital program was 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. 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. 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.

Credit facility

We had $143.0 million outstanding under our bank credit facility at December 31, 2005. This facility matures on March 31, 2007, 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

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125 to 200 basis points, or (b) the lead bank s reference rate plus an applicable margin ranging from 25 to 50 basis points. The effective rate of interest under our credit facility was 6.08% at December 31, 2005. Our borrowing base supported the entire $250.0 million commitment at December 31, 2005. The borrowing base is re-determined semi-annually, and borrowings under our credit facility are secured by liens on substantially all of our assets.

Our credit facility contains restrictive covenants that may limit our ability to, among other things, pay cash dividends, 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 Fixed Charge Coverage Ratio of not less than 1.25 to 1.0, a Total Funded Debt to EBITDA of no greater than 3.75 to 1.0 and a Total Funded Debt to Total Capitalization of no greater than .70 to 1.0. As of December 31, 2005, we were in compliance with all such covenants.

We are currently in negotiations with our lenders to enter into a new credit facility. We expect that the terms of the new facility will be at least as favorable as in the current bank facility. We anticipate completing negotiations before April 30, 2006.

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.

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.

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

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anticipated, we believe that our remaining cash balance and cash flows from operations will be sufficient to satisfy our 2006 capital budget. 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.

Shareholder distribution

The terms of our credit facility restrict our ability to pay dividends. However, because we are an S Corporation for federal income tax purposes, we are permitted to pay dividends to our shareholders in an amount sufficient to pay the taxes on the taxable income passed through to the shareholders. 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. Our board of directors approved a cash dividend of approximately $60.0 million to our shareholders and, subject to forfeiture, to holders of unvested restricted stock in April 2006. 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.

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 recognized hedging losses of $10.1 million and $6.4 million during 2003 and 2004, respectively.

Obligations and commitments

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

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

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

(2) 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 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 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.

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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 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.

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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 will adopt 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. Due to the liability classification, we do not expect SFAS 123(R) to have an impact on our results of operations as long as we are a non-reporting company.

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.

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

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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 their obligation to us, we may, if circumstances dictate, require collateral in the future. 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.

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 $143.0 million outstanding under our facility at December 31, 2005. The impact of a 1% increase in interest rates on this amount of debt would result in increased interest expense of approximately $1.4 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:

(in thousands)	2006	2007	Total	Fair value at December 31, 2005
Variable rate debt:				
Credit facility:				
Principal amount	$	$ 143,000	$ 143,000	$ 143,000

Weighted-average interest rate	6.08%

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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. These drillbit proved reserve additions replaced 309% of production during that period at an average drillbit finding cost of $5.89 per Boe.

As of December 31, 2005, our estimated proved reserves were 116.7 MMBoe, with a PV-10 of $2.2 billion. Estimated proved developed reserves were 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, we generated revenues of $375.8 million and operating cash flows of $265.3 million.

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 then ended 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 (in millions)	Net producing wells	Fourth quarter 2005 (Boe per day)	Percent of total	Annualized reserve/ production index(1)
Rocky Mountain:							
Red River units	67,711	58%	$ 1,215	187	9,792	44%	18.9
Bakken field	23,878	21%	501	34	5,999	27%	10.9
Other	9,228	8%	141	230	1,694	8%	14.9
Mid-Continent	15,472	13%	328	630	3,715	17%	11.4
Gulf Coast	376		19	23	973	4%	1.1

Total	116,665	100%	$ 2,204	1,104	22,173	100%	14.4

(1) 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 fourth quarter 2005 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				Capital expenditures
	Gross	Net	Gross	Net	Scheduled drilling locations(1)	Wells planned for drilling	(in millions)
Rocky Mountain:							
Red River units	144,176	128,047			135	41	$ 84
Bakken field	52,421	38,971	588,081	356,426	918	54	96
Other	45,720	36,153	358,649	208,612	71	34	40
Mid-Continent	152,734	99,279	115,746	73,582	96	70	64
Gulf Coast	41,842	11,890	23,598	7,873	13	13	17
Total	436,893	314,340	1,086,074	646,493	1,233	212	$ 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, 256 are classified as PUDs. As of March 1, 2006, we have commenced drilling of 27 locations shown in the table, including 15 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 own 168,000 gross (72,000 net) undeveloped acres in these projects, 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. These drillbit proved reserve additions replaced 309% of production during that five-year period and 450% of production during 2005 at an average drillbit finding cost of $5.89 and $4.37 per Boe, respectively.

Internally generate prospects. Our technical staff internally generates substantially all of the opportunities for the investment of our capital. Because we are typically an early entrant in new or emerging plays, our costs to acquire undeveloped acreage are generally 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 and Bakken 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 71% of our total oil and natural gas production during the three months ended December 31, 2005.

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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.

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 and have the potential to make the Bakken field one of our largest sources of growth of reserves and production over the next several years.

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 are currently drilling a horizontal Red River B well 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 61 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 significantly 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 December 31, 2005, production in the Red River units averaged approximately 9,792 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 39 waterflood units. Additionally, we operate eight of the eleven 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. Our drillbit finding costs were $4.37 per Boe and $5.89 per Boe over the one- and five-year periods ending December 31, 2005, respectively.

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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 eight senior officers have an average of 25 years of oil and gas industry experience. Additionally, our technical staff, which includes 21 petroleum engineers, 14 geoscientists and seven landmen, has an average of more than 19 years experience in the industry.

Strong financial position. As of December 31, 2005, we had outstanding borrowings under our credit facility of approximately $143.0 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 any hedges in place.

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 (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 of discounted future net cash flows(1)				$ 2,204

(1) The standardized measure of discounted future net cash flows is computed by applying year-end prices, costs and a discount factor of 10 percent to net proved reserves. 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.

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 (in millions)

Rocky Mountain:					
Red River units	61,881	34,980	67,711	75%	$ 1,215
Bakken field	22,121	10,544	23,878	45%	501
Other	8,609	3,714	9,228	65%	141
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

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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:

	Year ended December 31,		
	2003	**2004**	**2005**
Net production volumes:			
Oil (MBbls)	3,463	3,688	5,708
Natural gas (MMcf)	10,751	8,794	9,006
Oil equivalents (MBoe)	5,255	5,154	7,209
Average prices:			
Oil, without hedges ($/Bbl)	$ 28.88	$ 38.85	$ 52.45
Oil, with hedges ($/Bbl)	25.98	37.12	52.45
Natural gas ($/Mcf)	4.55	5.06	6.93
Oil equivalents, without hedges ($/Boe)	28.35	36.45	50.19
Oil equivalents, with hedges ($/Boe)	26.44	35.20	50.19
Costs and expenses:			
Production expense ($/Boe)	$ 7.77	$ 8.49	$ 7.32
Production tax ($/Boe)	1.95	2.39	2.22
General and administrative ($/Boe)	1.79	2.02	2.43
DD&A expense ($/Boe)	7.10	7.02	6.50

The following table sets forth information regarding our average daily production during the fourth quarter of 2005:

	Average daily production Fourth quarter 2005		
	Bbls	**Mcf**	**Boe**
Rocky Mountain			
Red River units	9,561	1,388	9,792
Bakken field	5,486	3,077	5,999
Other	1,433	1,567	1,694
Mid-Continent	1,511	13,222	3,715
Gulf Coast	91	5,293	973
Total	18,082	24,547	22,173

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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 19 gross (9.6 net) development wells and 6 gross (4.0 net) exploratory wells in the process of drilling. As of March 1, 2006, 13 gross (6.6 net) wells of the development wells in process as of December 31, 2005, were completed as producers and the remaining development wells were in the process of completion. As of March 1, 2006, 2 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 wells were in the process of completion.

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 then ended, our average production from such properties was 16,480 net Bbls of oil and 6,032 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.

Red River units

Our Red River units represented 65% of our PV-10 in the Rocky Mountain Region as of December 31, 2005 and 56% of our average daily Rocky Mountain Region equivalent production for the three months then ended. The eight units comprising the Red River units are located along the Cedar Hills Anticline 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.

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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 142 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 7,054 net Bbls per day in December 2005 from 2,185 Bbls per day in November 2003. As of December 31, 2005, the average density in the Cedar Hill units is approximately one producing wellbore each 653 acres. We currently plan to drill 111 new horizontal wellbores and 26 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 $42 million drilling in the Cedar Hills units.

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 17 vertical wells under HPAI producing 509 net Bbls of oil per day. We have since drilled 35 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 905 net Bbls of oil and 470 net Mcf of natural gas per day in December 2005. We currently plan to drill 20 new horizontal wellbores and seven 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 $14 million for drilling in MPHU.

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 76 vertical wells under HPAI producing approximately 1,821 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 December 2005 was 1,499 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 $11 million for drilling in the Buffalo Red River units.

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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 34% of our average daily Rocky Mountain Region equivalent production for the three months then ended. 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 277 productive wells with cumulative production as of October 2005 of 24 MMBbls of oil and 13 Bcf of natural gas. Daily production from these wells for the month of September 2005 was approximately 48 MBbls of oil and 29 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 177,100 gross Bbls of oil and 91,500 gross Mcf of natural gas as of December 2005 and averaged 112 gross Bbls of oil and 128 gross Mcf of natural gas per day during the month of December 2005. Cumulative production from the 42 operated wells drilled by us in Richland County was 3.8 gross MMBbls of oil and 1.6 gross Bcf of natural gas through December 31, 2005, with an average rate of 9,920 gross Bbls and 5,248 gross Mcf per day for the month of December 2005. Our average daily rate from operated and non-operated wells in this field (32 net wells) was approximately 5,400 net Bbls of oil and 3,150 net Mcf of natural gas during the month of December 2005. 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.

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 $58 million in the drilling of 35 horizontal Bakken wells in Montana during 2006.

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 February 21, 2006, production data had been reported to the North Dakota Oil and Gas Commission on 24 horizontal North Dakota Bakken wells completed during 2004 and 2005. The initial production rates on the 24 wells ranged up to 585 Boe per day and averaged 267 Boe per day per well. Cumulative and daily production from the 24 wells as of December 31, 2005 was 531 MBoe and 2,191 Boe, respectively.

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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 38,000 gross Boe through December 31, 2005 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 about 12,000 gross Boe through December 31, 2005 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.

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 $28 million in the drilling of 19 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 10% of our average daily Rocky Mountain Region equivalent production for the three months then ended. During the three months ended December 31, 2005, we produced an average of 1,433 net Bbls of oil and 1,567 net Mcf of natural gas per day from our 262 gross (230 net) 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 $17 million in the drilling of 16 wells in the Worland field and four Tensleep formation wells elsewhere in the Big Horn Basin.

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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 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 October 2005, the Triton field, located in the center of our acreage block, has produced a total of 6.5 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.

In December 2005, we participated with a 40% working interest in our initial well in this project. Significant gas shows were encountered while drilling in the Lewis Shale and several overlying uphole zones. The well is currently being tested. During 2006, we plan to invest approximately $13 million in the drilling of eight Lewis Shale wells.

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 a unit where 26 wells have been completed in the Pierre Shale formation from September 2003 through October 2005. Daily production from the 26 wells in October 2005 was approximately 2,500 Mcf of natural gas. In 2006, we plan to invest $1 million to drill four Pierre Shale wells on our acreage.

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 December 31, 2005, our average production from such properties was 1,511 net Bbls of oil and 13,222 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 72% of our average daily Mid-Continent Region equivalent production for the three months then ended. 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 then ended. 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 $8 million in the drilling of 30 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. 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. Over the last 18 months, 6 horizontal wells have been completed in the Woodford Shale near our acreage with initial production rates of up to 2,250 Mcf of natural gas per day. Four rigs are currently drilling horizontal wells in the Woodford Shale in close proximity to our acreage. During 2006, we plan to complete a 19-square mile 3D seismic shoot over our acreage to identify prospective drilling locations and anticipate investing approximately $5 million in the drilling of eight Woodford Shale wells.

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 December 31, 2005, our average production from our Gulf Coast properties was 91 net Bbls of oil and 5,293 net Mcf of natural gas per day. Principally as a result of two successful recompletions in January 2006, production in the region increased to 416 net Bbls of oil and 6,708 Mcf of natural gas per day during January 2006. Our principal producing properties in this region are located in South Texas and Louisiana. In 2006, we plan to invest approximately $14 million in the drilling of 13 wells in the Texas and Louisiana Gulf Coast.

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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 Pipeline Company, L.L.C. and Nexen Marketing U.S.A. Inc. accounted for approximately 31%, 19% and 10%, respectively, of our total oil and gas sales. Banner Pipeline Company, L.L.C. is an affiliate of ours as described under Certain relationships and related party transactions. We believe that the loss of any 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.

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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 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.

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

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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 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 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. In September 2004, we were notified by EPA Region 8 that it was initiating an administrative enforcement action under the SDWA based on our alleged failure to comply with certain requirements relating to four injection wells on the Fort Peck Indian Reservation in Valley County, Montana. The EPA initially proposed to impose a penalty of $134,600, but we have been negotiating a proposed settlement with EPA and currently expect that this matter will be

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resolved for a penalty amount of less than $100,000. It is possible that there may be other instances of non-compliance with SDWA requirements from time to time in connection with our operations.

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. We are currently working with the South Dakota Department of Environment and Natural Resources to reduce our emissions of volatile organic compounds from our facilities in Harding County, South Dakota and expect to incur approximately $5 million in capital expenditures in connection with such efforts.

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

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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.

Employees

As of December 31, 2005, we employed 286 people, including 161 employees in drilling and production, 43 in financial and accounting, 25 in land, 17 in exploration, 15 in reservoir engineering, 15 in administrative and 10 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)(4)	60	Chairman, Chief Executive Officer and Director
Mark E. Monroe(3)	51	President, Chief Operating Officer and Director
John D. Hart	38	Vice President, Chief Financial Officer and Treasurer
Jeffrey B. Hume	54	Senior Vice President Resource and Business Development
Tom E. Luttrell	48	Senior Vice President Land
Gerald B. Smith	51	Senior Vice President Drilling and Production
Jack H. Stark(3)	51	Senior Vice President Exploration and Director
Richard H. Straeter	47	President Continental Resources of Illinois, Inc.
Robert J. Grant(2)(5)	67	Director
George S. Littell(4)	61	Director
Lon McCain(1)(2)(3)	58	Director
H. R. Sanders, Jr.(1)(2)(5)	73	Director

(1) Member of the compensation committee.

(2) Member of the audit committee.

(3) Term expires in 2006.

(4) Term expires in 2007.

(5) Term expires in 2008.

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 as a director of Complete Production

Services, Inc., an oil and gas service company that has recently filed a registration statement with the SEC in connection with its proposed initial public offering. 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

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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, a 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.

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 Resource and Business Development in October 2005. He was previously elected as 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.

Gerald B. Smith became Senior Vice President Drilling and Production in August 2003. Prior to joining us, Mr. Smith held various positions with Anadarko Petroleum Corporation for over 26 years, including Manager, Operations for Anadarko s Mid-Continent Division from 1997 to 2003. Mr. Smith is a Registered Professional Engineer. Mr. Smith graduated from the University of Missouri-Rolla with a Bachelor of Science degree in Petroleum Engineering.

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 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,

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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 has also been an Adjunct Professor of Finance at the University of Denver since 1982. 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.

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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 2006, 2007 and 2008, 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.

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.

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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 $5,000 and each Chairman of the other committees is paid an annual 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, 300 shares of restricted stock were granted each to Messrs. Grant, Littell and Sanders. In February 2006, 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.

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(1)**	**Other Annual Compen-sation(2)**	**Restricted Stock Awards(3)**	**Number of Securities Underlying Options**	**All Other Compen-sation(4)**
Harold G. Hamm	Chairman and Chief Executive Officer	2005	$ 350,000		$ 46,300	$ 2,948,400		$ 10,500

Jeffrey B. Hume	Senior Vice President Resource and Business Development	2005	$ 197,538			$ 442,260		$ 9,877
Tom E. Luttrell	Senior Vice President Land	2005	$ 165,154				15,000	$ 8,258
Gerald B. Smith	Senior Vice President Drilling and Production	2005	$ 233,846					$ 10,500
Jack H. Stark	Senior Vice President Exploration	2005	$ 214,231			$ 442,260		$ 10,500

(1) Bonuses paid for services rendered in 2005. Bonuses paid in 2005 for services rendered in 2004 by Messrs. Hamm, Hume, Luttrell, Smith and Stark were $0, $92,505, $88,521, $150,422 and $117,520, respectively.

(2) 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.

(3) The restricted stock awards issued to Messrs. Hamm, Hume and Stark of 20,000 shares, 3,000 shares and 3,000 shares, respectively, vest ratably over three years. The value of these shares has been determined based on the fair market value

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methodology set forth in the award agreements based on the book value of our shareholders equity adjusted for quarter-end reserve valuations.

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

Stock options granted during 2005