CONTINENTAL RESOURCES INC
Form 10-K
February 27, 2009
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UNITED STATES

SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

FORM 10-K

(Mark One)

x ANNUAL REPORT PURSUANT TO SECTION 13 OR 15 (d) OF THE SECURITIES EXCHANGE ACT OF 1934
For the fiscal year ended December 31, 2008

OR

¨ TRANSITION REPORT PURSUANT TO SECTION 13 OR 15 (d) OF THE SECURITIES EXCHANGE ACT OF 1934
For the transition period from to

Commission File Number: 001-32886

CONTINENTAL RESOURCES, INC.

(Exact name of registrant as specified in its charter)

Oklahoma	**73-0767549**
(State or other jurisdiction of incorporation or organization)	**(I.R.S. Employer Identification No.)**
302 N. Independence, Suite 1500, Enid, Oklahoma	**73701**
(Address of principal executive offices)	**(Zip Code)**

Registrant s telephone number, including area code: (580) 233-8955

Securities registered under Section 12(b) of the Exchange Act:

Title of Class	**Name of Exchange on Which Registered**
Common Stock, $0.01 par value	New York Stock Exchange

Securities registered under Section 12(g) of the Exchange Act: None

Indicate by check mark if registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act. Yes x No ¨

Indicate by check mark if registrant is not required to file reports pursuant to Section 13 or Section 15(d) of the Act. Yes ¨ No x

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15 (d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days. Yes x No ¨

Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K is not contained herein, and will not be contained, to the best of registrant s knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10-K or any amendment to this Form 10-K. ¨

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer or a smaller reporting company. See definition of accelerated filer , large accelerated filer and smaller reporting company in Rule 12b-2 of the Exchange Act.

Large accelerated filer x Accelerated filer ¨ Non-accelerated filer ¨ Smaller reporting company ¨

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Exchange Act). Yes ¨ No x

State the aggregate market value of the voting and non-voting common equity held by non-affiliates computed by reference to the price at which the common equity was last sold, or the average bid and asked prices of such common equity, as of the last business day of the registrant s most recently completed second fiscal quarter. As of June 30, 2008 aggregate market value was $3,138,228,490.

As of February 23, 2009, the registrant had 169,556,833 shares of common stock outstanding.

DOCUMENTS INCORPORATED BY REFERENCE

Portions of the definitive Proxy Statement of Continental Resources, Inc. for the Annual Meeting of Stockholders to be held May 28, 2009, which will be filed with the Commission no later than April 30, 2009 are incorporated by reference into Part III of this Form 10-K.

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Glossary of Oil and Natural Gas Terms

The terms defined in this section are used throughout this report:

AMI. Area of mutual interest.

Bbl. One stock tank barrel, of 42 U.S. gallons liquid volume, used herein in reference to crude oil, condensate or natural gas liquids.

Bcf. One billion cubic feet of natural gas.

Bcfe. One billion cubic feet of natural gas equivalent with one barrel of oil converted to six thousand cubic feet of natural gas.

Boe. Barrels of oil equivalent, with six thousand cubic feet of natural gas being equivalent to one barrel of oil.

Basin. A large natural depression on the earth s surface in which sediments generally brought by water accumulate.

Completion. The process of treating a drilled well followed by the installation of permanent equipment for the production of natural gas or oil, or in the case of a dry hole, the reporting of abandonment to the appropriate agency.

DD&A. Depreciation, depletion, amortization and accretion.

Developed acreage. The number of acres that are allocated or assignable to productive wells or wells capable of production.

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

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

Enhanced recovery. The recovery of oil and natural gas through the injection of liquids or gases into the reservoir, supplementing its natural energy. Enhanced recovery methods are often applied when production slows due to depletion of the natural pressure.

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

Field. An area consisting of a single reservoir or multiple reservoirs all grouped on, or related to, the same individual geological structural feature or stratigraphic condition. The field name refers to the surface area, although it may refer to both the surface and the underground productive formations.

Formation. A layer of rock which has distinct characteristics that differs from nearby rock.

Horizontal drilling. A drilling technique used in certain formations where a well is drilled vertically to a certain depth and then drilled at a right angle within a specified interval.

HPAI. High pressure air injection.

Infill wells. Wells drilled into the same pool as known producing wells so that oil or natural gas does not have to travel as far through the formation.

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MBbl. One thousand barrels of crude oil, condensate or natural gas liquids.

Mcf. One thousand cubic feet of natural gas.

MBoe. One thousand Boe.

MMBoe. One million Boe.

MMBtu. One million British thermal units.

MMcf. One million cubic feet of natural gas.

NYMEX. The New York Mercantile Exchange.

Net acres. The percentage of total acres an owner has out of a particular number of acres, or a specified tract. An owner who has 50% interest in 100 acres owns 50 net acres.

PUD. Proved undeveloped.

PV-10. When used with respect to oil and natural gas reserves, PV-10 means the estimated future gross revenue to be generated from the production of proved reserves, net of estimated production and future development and abandonment costs, using prices and costs in effect at the determination date, before income taxes, and without giving effect to non-property-related expenses, discounted to a present value using an annual discount rate of 10% in accordance with the guidelines of the SEC. PV-10 is not a financial measure calculated in accordance with generally accepted accounting principles (GAAP) and generally differs from Standardized Measure, the most directly comparable GAAP financial measure, because it does not include the effects of income taxes on future net revenues. Neither PV-10 nor Standardized Measure represents an estimate of the fair market value of our oil and gas properties. We and others in the industry use PV-10 as a measure to compare the relative size and value of proved reserves held by companies without regard to the specific tax characteristics of such entities.

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

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

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

Proved undeveloped reserves (*PUD*). Proved reserves that are expected to be recovered from new wells on undrilled acreage or from existing wells where a relatively major expenditure is required for recompletion.

Reservoir. A porous and permeable underground formation containing a natural accumulation of producible oil and/or natural gas that is confined by impermeable rock or water barriers and is separate from other reservoirs.

Simul-Frac. Simultaneously fracture treating two or more wells within the same fracture plane in order to create pressure interference between the wells and thereby increasing the stimulated reservoir volume.

Spacing. The distance between wells producing from the same reservoir. Spacing is often expressed in terms of acres, e.g., 40-acre spacing, and is often established by regulatory agencies.

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Standardized Measure. Discounted future net cash flows estimated by applying year-end prices to the estimated future production of year-end proved reserves. Future cash inflows are reduced by estimated future production and development costs based on period-end costs to determine pre-tax cash inflows. Future income taxes, if applicable, are computed by applying the statutory tax rate to the excess of pre-tax cash inflows over our tax basis in the oil and gas properties. Future net cash inflows after income taxes are discounted using a 10% annual discount rate.

Unit. The joining of all or substantially all interests in a reservoir or field, rather than a single tract, to provide for development and operation without regard to separate property interests. Also, the area covered by a unitization agreement.

Waterflood. The injection of water into an oil reservoir to push additional oil out of the reservoir rock and into the wellbores of producing wells. Typically an enhanced recovery process.

Wellbore. The hole drilled by the bit that is equipped for oil or gas production on a completed well. Also called well or borehole.

Working interest. The right granted to the lessee of a property to explore for and to produce and own oil, gas, or other minerals. The working interest owners bear the exploration, development, and operating costs on either a cash, penalty, or carried basis.

Cautionary Statement Regarding Forward-Looking Statements

This report contains forward-looking statements within the meaning of Section 27A of the Securities Act of 1933 and Section 21E of the Securities Exchange Act of 1934, as amended. These forward-looking statements 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 report, 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 report, 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. Except as otherwise specifically indicated, these statements assume no significant changes will occur in the operating environment for oil and natural gas properties and that there will be no material acquisitions, divestitures or financings except as otherwise described.

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;

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- costs of exploiting and developing our properties and conducting other operations;
- general economic conditions;
- credit markets;
- liquidity and access to capital;
- uncertainty regarding our future operating results; and
- plans, objectives, expectations and intentions contained in this report that are not historical.

All forward-looking statements speak only as of the date of this report. 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 report 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 Item 1A. Risk Factors and Item 7. Management s Discussion and Analysis of Financial Condition and Results of Operation and elsewhere in this report. These cautionary statements qualify all forward-looking statements attributable to us or persons acting on our behalf.

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Part I

You should read this entire report carefully, including Risk Factors and our historical consolidated financial statements and the notes to those historical consolidated financial statements included elsewhere in this report. Unless the context otherwise requires, references in this report to Continental Resources, we, us, our, or ours refer to Continental Resources, Inc., and its subsidiary.

Item 1. Business

General

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 were originally formed in 1967 to explore, develop and produce oil and natural gas properties. 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. Approximately 70% of our estimated proved reserves as of December 31, 2008 are located in the Rocky Mountain region. We completed an initial public offering of our common stock on May 14, 2007, and our common stock began trading on the New York Stock Exchange on May 15, 2007 under the ticker symbol CLR .

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 121.7 MMBoe of proved oil and natural gas reserves through extensions and discoveries from January 1, 2004 through December 31, 2008 compared to 3.1 MMBoe added through proved reserve purchases during that same period.

As of December 31, 2008, our estimated proved reserves were 159.3 MMBoe, with estimated proved developed reserves of 106.0 MMBoe, or 67% of our total estimated proved reserves. Crude oil comprised 67% of our total estimated proved reserves. For the year ended December 31, 2008, we generated revenues of $960.5 million and operating cash flows of $719.9 million. For the year and quarter ended December 31, 2008, daily production averaged 32,803 and 36,018 Boe per day, respectively. This represents growth of 13% and 19% as compared to the year and quarter ended December 31, 2007, when daily production averaged 29,099 Boe and 30,369 Boe, respectively.

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The following table summarizes our total estimated proved reserves, PV-10 and net producing wells as of December 31, 2008, average daily production for the three months ended December 31, 2008 and the reserve-to-production index in our principal regions. Our reserve estimates as of December 31, 2008 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, 2008				Average daily production fourth quarter 2008 (Boe per day)		
	Proved reserves (MBoe)	Percent of total	PV-10[1] (in millions)	Net producing wells		Percent of Total	Annualized reserve/ production index[2]
Rockies:							
Red River units	59,386	37.3%	$ 697	242	14,058	39.0%	11.5
Bakken field							
Montana Bakken	28,228	17.7%	240	100	6,410	17.8%	12.0
North Dakota Bakken	17,507	11.0%	160	48	4,401	12.2%	10.9
Other	6,900	4.3%	62	272	2,508	7.0%	7.5
Mid-Continent:							
Arkoma Woodford	30,749	19.3%	184	42	3,276	9.1%	25.6
Other	16,062	10.1%	170	752	4,750	13.2%	9.2
Gulf Coast	430	0.3%	10	17	615	1.7%	1.9
Total	159,262	100.0%	$ 1,523	1,473	36,018	100.0%	12.1

(1) PV-10 is a non GAAP financial measure and generally differs from Standardized Measure, the most directly comparable GAAP financial measure, because it does not include the effects of income taxes on future net revenues. The Standardized Measure at December 31, 2008 is $1.3 billion, a $0.2 billion difference from PV-10 because of the tax effect. Neither PV-10 nor Standardized Measure represents an estimate of the fair market value of our oil and gas properties. We and others in the industry use PV-10 as a measure to compare the relative size and value of proved reserves held by companies without regard to the specific tax characteristics of such entities.

(2) The Annualized Reserve/Production Index is the number of years proved reserves would last assuming current production continued at the same rate. This index is calculated by dividing annualized fourth quarter 2008 production into the proved reserve quantity at December 31, 2008.

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

	Developed acres		Undeveloped acres		Gross wells planned for drilling	Capital expenditures (in millions)[1]
	Gross	Net	Gross	Net		
Rockies:						
Red River units	147,235	131,320			4	$ 46
Bakken field						
Montana Bakken	82,182	64,438	131,422	101,010		7
North Dakota Bakken	76,337	37,135	865,116	378,425	86	72
Other	61,963	46,818	309,741	189,818	2	2
Mid-Continent:						
Arkoma Woodford	61,461	13,288	99,158	33,568	63	56
Other	138,437	95,093	584,215	382,377	19	27
Gulf Coast	40,748	11,733	36,304	29,247		1
Total	608,363	399,825	2,025,956	1,114,445	174	$ 211

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(1) Capital expenditures budgeted for 2009 includes amounts for drilling, capital workovers and facilities and excludes amounts for land of $54 million, seismic of $4 million, and $6 million for vehicles, computers and other equipment. While the above capital expenditures budget reflects our current intentions, we intend to manage our 2009 capital expenditures to be inline with our cash flow from operations. Continued weakness in oil and natural gas prices could cause us to curtail our actual capital expenditures. Conversely, an increase in commodity prices could result in increased capital expenditures.

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:

Focus on Oil. During the late 1980 s we began to believe that the valuation potential for crude oil exceeded that of natural gas. Accordingly, we began to shift our reserve and production profiles towards crude oil. As of December 31, 2008, crude oil comprises 67% of our total proved reserves and 76% of our 2008 annual production. Although we do pursue natural gas opportunities, we continue to believe that crude oil valuations will be superior to natural gas valuations on a relative Btu basis.

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, 2004 through December 31, 2008, proved oil and natural gas reserve additions through extensions and discoveries were 121.7 MMBoe compared to 3.1 MMBoe of proved reserve purchases.

Internally Generate Prospects. Our technical staff has internally generated substantially all of the opportunities for the investment of our capital. As an early entrant in new or emerging plays, we expect to acquire undeveloped acreage at a lower cost than those of later entrants into a developing play.

Focus on Unconventional Oil and Natural Gas Resource Plays. Our experience with horizontal drilling, advanced fracture stimulation and enhanced recovery technologies allows us to commercially develop unconventional oil and natural gas resource plays, such as the Red River B dolomite, Bakken Shale and Arkoma Woodford 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, the Bakken field, and the Arkoma Woodford comprised approximately 9,302 MBoe, or 77% of our total oil and natural gas production during the year ended December 31, 2008.

Acquire Significant Acreage Positions in New or Developing Plays. In addition to the 513,003 net undeveloped acres held in the Montana and North Dakota Bakken shale and Arkoma Woodford fields, we held 359,120 net undeveloped acres in other oil and natural gas shale plays as of December 31, 2008. 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 Acreage Inventory. We own 1,114,445 net undeveloped and 399,825 net developed acres as of December 31, 2008. Approximately 78% of the undeveloped acres are located within unconventional shale resource plays including the Bakken shale in North Dakota and Montana, the Woodford shale in southeast and western Oklahoma, the Atoka shale in western Oklahoma and the Texas Panhandle, the New Albany shale in Indiana and Kentucky and the Lower Huron, Rhinestreet and Marcellus shales in West Virginia, Pennsylvania, New York and Ohio. The balance of the undeveloped acreage is located primarily in conventional plays including 3D defined locations for the Trenton-Black River of Michigan, Red River of Montana and North Dakota, Morrow-Springer of western Oklahoma and Frio in South Texas.

Horizontal Drilling and Enhanced Recovery Experience. In 1992, we drilled our initial horizontal well, and we have drilled over 600 horizontal wells since that time. We also have substantial experience with enhanced recovery methods and currently serve as the operator of 48 waterflood units. Additionally, we operate eight high pressure air injection (HPAI) floods.

Control Operations Over a Substantial Portion of Our Assets and Investments. As of December 31, 2008, we operated properties comprising 91% of our PV-10. By controlling operations, we are able to more effectively manage the cost and timing of exploration and development of our properties, including the drilling and fracture stimulation methods used.

Experienced Management Team. Our senior management team has extensive expertise in the oil and gas industry. Our Chief Executive Officer, Harold G. Hamm, began his career in the oil and gas industry in 1967. Our seven senior officers have an average of 28 years of oil and gas industry experience. Additionally, our technical staff, which includes 27 petroleum engineers, 17 geoscientists and 11 landmen, has an average of 20 years experience in the industry.

Strong Financial Position. As of February 23, 2009, we had outstanding borrowings under our revolving credit facility of approximately $474.4 million and available borrowing capacity under our selected commitment level of $198.1 million. We have elected to set the commitment level at $672.5 million, which is below the revolving credit facility note amount of $750.0 million and the established borrowing base of $850.0 million. We believe that our planned exploration and development activities will be funded substantially from our operating cash flows and borrowings under our revolving credit facility. Our 2009 capital expenditures budget has been established based on our current expectation of available cash flow from operations. Should expected available cash flow from operations materially vary from expectations, we believe our credit facility has sufficient availability to fund any deficit or that we can further reduce our capital expenditures to be in line with cash flow from operations.

Oil and Gas Operations

Proved Reserves

The following tables set forth our estimated proved oil and natural gas reserves, percent of total proved reserves that are proved developed, the PV-10 and standardized measure of discounted future net cash flows as of December 31, 2008 by reserve category and region. 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. The year-end weighted average oil and natural gas prices used in the computation of future net cash flows at December 31, 2008 were $39.69 per barrel and $4.90 per Mcf, respectively.

	December 31, 2008			
	Oil (MBbls)	Gas (MMcf)	Total (MBoe)	PV-10(1) (in millions)
Proved developed producing	79,845	153,038	105,351	$ 1,267
Proved developed non-producing	542	498	625	5
Proved undeveloped	25,852	164,602	53,286	251
Total proved reserves	106,239	318,138	159,262	$ 1,523
Standardized measure				$ 1,277

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	Oil (MBbls)	Gas (MMcf)	Total (MBoe)	% Proved developed	PV-10[1] (in millions)
Rockies:					
Red River units	54,917	26,812	59,386	85%	$ 697
Bakken field					
Montana Bakken	24,154	24,443	28,228	64%	240
North Dakota Bakken	14,832	16,047	17,507	52%	160
Other	5,524	8,255	6,900	99%	62
Mid-Continent:					
Arkoma Woodford	62	184,120	30,749	24%	184
Other	6,657	56,439	16,062	86%	170
Gulf Coast	93	2,022	430	100%	10
Total	106,239	318,138	159,262	67%	$ 1,523

(1) PV-10 is a non GAAP financial measure and generally differs from Standardized Measure, the most directly comparable GAAP financial measure, because it does not include the effects of income taxes on future net revenues. The Standardized Measure at December 31, 2008 is $1.3 billion, a $0.2 billion difference from PV-10 because of the tax effect. Neither PV-10 nor Standardized Measure represents an estimate of the fair market value of our oil and gas properties. We and others in the industry use PV-10 as a measure to compare the relative size and value of proved reserves held by companies without regard to the specific tax characteristics of such entities.

Developed and Undeveloped Acreage

The following table presents the total gross and net developed and undeveloped acreage by region as of December 31, 2008:

	Developed acres		Undeveloped acres		Total	
	Gross	Net	Gross	Net	Gross	Net
Rockies:						
Red River units	147,235	131,320			147,235	131,320
Bakken field						
Montana Bakken	82,182	64,438	131,422	101,010	213,604	165,448
North Dakota Bakken	76,337	37,135	865,116	378,425	941,453	415,560
Other	61,963	46,818	309,741	189,818	371,704	236,636
Mid-Continent:						
Arkoma Woodford	61,461	13,288	99,158	33,568	160,619	46,856
Other	138,437	95,093	584,215	382,377	722,652	477,470
Gulf Coast	40,748	11,733	36,304	29,247	77,052	40,980
Total	608,363	399,825	2,025,956	1,114,445	2,634,319	1,514,270

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The following table sets forth the number of gross and net undeveloped acres as of December 31, 2008 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:

	2009		2010		2011	
	Gross	Net	Gross	Net	Gross	Net
Rockies:						
Red River units						
Bakken field						
Montana Bakken	18,037	10,920	24,557	19,510	57,527	48,367
North Dakota Bakken	156,404	83,394	137,899	59,424	224,552	79,934
Other	49,311	20,334	37,656	20,141	56,662	41,995
Mid-Continent:						
Arkoma Woodford	49,015	17,005	23,808	8,801	15,225	6,811
Other	24,848	18,009	207,604	113,643	236,500	157,324
Gulf Coast	3,200	2,443	5	3	29,586	25,692
Total	300,815	152,105	431,529	221,522	620,052	360,123

Drilling Activity

During the three years ended December 31, 2008, we drilled exploratory and development wells as set forth in the table below:

	2008		2007		2006	
	Gross	Net	Gross	Net	Gross	Net
Exploratory wells:						
Oil	41	18.2	33	15.6	17	8.4
Natural gas	73	19.5	79	13.1	25	4.9
Dry	12	8.9	4	2.5	17	9.4
Total exploratory wells	126	46.6	116	31.2	59	22.7
Development wells:						
Oil	153	89.3	92	69.5	83	57.0
Natural gas	72	13.4	49	10.3	34	14.5
Dry	8	3.2	5	1.1	7	4.3
Total development wells	233	105.9	146	80.9	124	75.8
Total wells	359	152.5	262	112.1	183	98.5

As of December 31, 2008, there were 117 gross (40 net) wells in the process of drilling, completing or waiting on completion.

As of February 23, 2009, we operated 7 rigs on our properties. Our rig activity during 2009 will be highly dependent on oil and natural gas prices and accordingly our rig count may increase or decrease from current levels. There can be no assurance, however, that additional rigs will be available to us at an attractive cost. See Risk Factors The unavailability or high cost of additional drilling rigs, equipment, supplies, personnel and oilfield services could adversely affect our ability to execute our exploration and development plans within our budget and on a timely basis.

Summary of Oil and Natural Gas Properties and Projects

Throughout the following discussion, we discuss our budgeted number of wells and capital expenditures. While the discussion reflects our current intentions, we intend to manage 2009 capital expenditures to be inline with our cash flow from operations. Continued weakness in oil and natural gas prices could cause us to curtail our actual capital expenditures. Conversely, an increase in commodity prices could result in increased capital expenditures.

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Rocky Mountain Region

Our properties in the Rocky Mountain region represented 76% of our PV-10 as of December 31, 2008. During the three months ended December 31, 2008, our average daily production from such properties was 24,536 net Bbls of oil and 17,041 net Mcf of natural gas. Our principal producing properties in this region are in the Red River units, the Bakken field and the Big Horn Basin.

Red River Units

Our Red River units represented 59.6% of our PV-10 in the Rocky Mountain region as of December 31, 2008 and 51% of our average daily Rocky Mountain region Boe production for the three months ended December 31, 2008. The eight units comprising the Red River units are located along the Cedar Creek 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 2007 as the 6th largest onshore, lower 48 field in the United States ranked by liquid proved reserves.

Cedar Hills Units. The Cedar Hills North unit (CHNU) is located in Bowman and Slope Counties, North Dakota. We drilled the initial horizontal well in the CHNU, the Ponderosa 1-15, in April 1995. As of December 31, 2008, we had drilled 225 horizontal wells within this 49,700-acre unit, with 128 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, 2008, this 7,800-acre unit contained eleven horizontal producing wells and six horizontal injection 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, water injection and increased density drilling operations, production from the Cedar Hills units increased to 11,451 net Boe per day in December 2008 from 2,185 net Boe per day in November 2003. As of December 31, 2008, the average density in the Cedar Hill units was approximately one producing wellbore per 420 acres. We currently plan to drill 4 new horizontal wellbores and 2 horizontal extensions of existing wellbores in the Cedar Hills units during 2009, increasing the density of both the producing and injection wellbores. The reduced distance between wells allows part of the field to be converted from air injection to water injection. This conversion began in 2008 and is forecast to lower operating expenses, as water is less costly to inject than air. In 2009, we plan to invest approximately $41.3 million drilling and improving facilities in the Cedar Hills units. This expenditure is lower than previously forecast due to the elimination of 25 gross wells from the increased density development program. This adjustment to the plan is a result of reduced commodity prices. The peak rate for the field will be reduced but we expect no reduction in ultimate reserves.

On August 22, 2007 the Hiland Partners, LP (Hiland) Badlands gas plant became operational for the processing and treatment of gas produced from the CHNU, CHWU and Medicine Pole Hills Unit. Under the terms of the November 8, 2005 contract we deliver low pressure gas to Hiland for compression, treatment and processing. Nitrogen and carbon dioxide must be removed from the gas production associated with oil production from the units for the gas production to be marketable. We pay $0.60 per Mcf in gathering and treating fees, and 50% of the electrical costs attributable to compression and plant operation and receive 50% of the proceeds from residue gas and plant product sales. After we deliver 36 Bcf of gas, the $0.60 per Mcf gathering and treating fee is eliminated. During December 2008, we sold 7,800 net Mcf of natural gas per day from 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-

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acre unit consisted of 18 vertical producing wellbores and four injection wellbores under HPAI producing 525 net Bbls of oil per day. We have since drilled 47 horizontal wellbores extending production to the west with the formation of the 15,000-acre Medicine Pole Hills West unit and to the south, with the 11,500-acre Medicine Pole Hills South unit. All three units are under HPAI. We operate and own an average 77% working interest in the three units. Production from the units averaged 1,391 net Bbls of oil and 178 net Mcf of natural gas per day during December 2008. During 2008 we drilled 7 new horizontal wellbores, 2 horizontal extensions of existing wellbores, and 2 horizontal re-entries of vertical wellbores, increasing the density of both producing and injection wellbores. We believe these operations will increase production and sweep efficiency. In 2009, we plan to invest approximately $3.4 million for capital workover and facilities in MPHU.

Buffalo Red River Units. Three contiguous Buffalo Red River units (Buffalo, West Buffalo and South Buffalo) are located in Harding County, South Dakota, approximately 21 miles south of the MPHU. When we purchased the units in 1995, there were 73 vertical producing wellbores and 38 injection wellbores under HPAI producing approximately 1,906 net Bbls of oil per day. We operate and own an average working interest of 95% in the 32,900 acres comprising the three units. From 2005 through 2008, we re-entered 48 existing vertical wells and drilled horizontal laterals to increase production and sweep efficiency from the three units. Production for the month of December 2008 was 1,670 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. In 2009, we plan to invest $0.7 million for capital workover and facilities in the Buffalo Red River units.

Bakken Field

We control one of the largest acreage positions in the Bakken field of Montana and North Dakota with approximately 1,155,000 gross (581,000 net) acres as of December 31, 2008. Approximately 17% of the net acreage is producing and 83% of the net acreage is undeveloped as of December 31, 2008. Our properties within the Bakken field in Montana and North Dakota represented 35% of our PV-10 in the Rocky Mountain region as of December 31, 2008 and 39% of our average daily Rocky Mountain region Boe production for the three months ended December 31, 2008. As of December 31, 2008 we had completed 308 gross (148.5 net) wells in the Bakken field.

The Bakken formation or Bakken Shale , as it is often called, is one of the most actively drilled unconventional oil resource plays in the United States with approximately 83 rigs drilling in the play as of December 31, 2008, including 76 in North Dakota and seven in Montana. A report issued by the United States Geologic Survey (USGS) in April 2008 estimates that the Bakken Shale contains up to 4.3 billion barrels of recoverable oil using today s technology and classifies it as the largest continuous oil accumulation ever assessed by the USGS.

The Bakken formation is a Devonian-age shale found within the Williston Basin underlying portions of North Dakota and Montana that contains three lithologic members including the upper shale, middle member and lower shale that combined range up to 130 feet thick. The upper and lower shales are highly organic, thermally mature and over pressured and act as both a source and reservoir for the oil. The middle member, which varies in composition from a silty dolomite to shalely limestone or sand, also serves as a reservoir and is thought to be a critical component for commercial production. The Three Forks/Sanish formation found immediately under the Lower Bakken Shale has also proven to contain productive reservoir rock that may add incremental reserves to the play. The Three Forks/Sanish typically consists of interbedded dolomites and shale with local development of a discontinuous sandy member at the top, known as the Sanish sand. All of these reservoir rocks have low porosity and permeability and depend on natural fracturing and artificial fracture stimulation to produce economically. Horizontal drilling and multi-stage fracture stimulation technology has enabled commercial production from this historically non-commercial reservoir. Generally, the Bakken formation is found at vertical depths of 9,000 to 10,500 feet and drilled horizontally on 320, 640 or 1,280-acre spacing with single, dual or triple leg horizontal laterals extending 4,500 to 9,000 feet into the formation. These wells are fracture stimulated to maximize recovery and economic returns. The fracture stimulation techniques vary but most commonly utilize multi-stage mechanically diverted stimulations using un-cemented liners and packers.

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Montana Bakken. Our Montana Bakken production is located in the Elm Coulee field in Richland County, Montana. The Elm Coulee field is listed by the Energy Information Administration as the 16th largest onshore, lower 48 field in the United States ranked by liquid proved reserves. Since drilling our first well in August 2003, we have completed a total of 156 gross (100.2 net) wells in the field as of December 31, 2008. Our daily average production from these wells was approximately 5,727 net Bbls of oil and 3,944 net Mcf of natural gas during the month of December 2008. The field has been developed exclusively with horizontal drilling and has been substantially drilled on 640-acre spacing. During 2008, we began to further develop our acreage in the field on 320 acre spacing and have identified 57 undrilled 320 acre infield locations on our acreage as of December 31, 2008. Out of the 22 gross (16.2 net) wells we drilled in the field during 2008, 12 gross (10.3 net) were 320 acre infield wells. These wells are performing in line with our expected reserve model of 279 MBoe per well.

In December 2008 we also began operations on a one well secondary recovery pilot project to evaluate the potential to increase oil recovery from the Bakken reservoir utilizing CO_2 injection. Laboratory tests indicate this technique is feasible and could increase oil recovery from the Bakken reservoir. Using a technique known as the huff and puff method, we began injecting CO_2 in January 2009 and expect to complete the injection phase by March 2009. After allowing the CO_2 to soak into the reservoir for approximately 30 days, we will flow the CO_2 and associated fluids back from the well. Production from the well will be measured and the performance will be analyzed to assess the incremental recovery and economics of the technique.

As of December 31, 2008, we held 131,422 gross (101,010 net) undeveloped acres in the Montana Bakken play within and adjacent to the Elm Coulee field. We have recently suspended drilling in the Montana Bakken due to weakness in oil and natural gas prices and will resume drilling as prices improve.

North Dakota Bakken. Our 2008 drilling program significantly expanded the proven extents of our North Dakota Bakken acreage along the Nesson anticline. During the year we completed 98 gross (27.2 net) wells and exited 2008 producing at an average daily rate of 5,081net Bbls of oil during the month of December 31, 2008, a 276% increase over the same period in 2007 and 1,744 net Mcf of natural gas during the month of December 2008, an increase of 113% over the same period in 2007.

During the year we drilled almost exclusively 1,280-acre spaced, long single leg laterals, up to 9,000 feet long and fracture stimulated these wells with up to 14 mechanically diverted stages using un-cemented liners and packers. We found this technique provided better wellbore integrity and on average delivered higher initial flow rates. Of significance, we completed 27 gross (10.3 net) Three Forks/Sanish wells during 2008. The Three Forks/Sanish formation which lies immediately below the lower Bakken shale is known to be productive locally throughout the Williston Basin and may add incremental reserves to the Bakken play. Our Three Forks/Sanish completions were strategically located throughout our acreage along the Nesson anticline over a distance of approximately 100 miles north to south. The success of these Three Forks/Sanish wells demonstrates the widespread productive potential of the Three Forks/Sanish reservoir underlying our acreage. Although the results in themselves do not demonstrate the Three Forks/Sanish formation adds incremental reserves to the Bakken play, it is notable that the 20 gross (8.9 net) Three Forks/Sanish completions we operated in 2008 had an average initial production rate of 640 gross Boe per day which is 17% higher than our average operated Middle Bakken completion in 2008.

As of December 31, 2008, we held 865,000 gross (378,000 net) undeveloped acres in the North Dakota Bakken field. As of February 23, 2009, we had 10 rigs drilling in the North Dakota Bakken field, including 4 operated by Continental Resources, Inc, and 6 operated by ConocoPhillips through a joint-venture. We plan to invest $71 million drilling 86 gross (20.2 net) wells in the North Dakota Bakken field during 2009.

Big Horn Basin and Other Rockies

Our wells within the Big Horn Basin in northern Wyoming and other areas within the Rocky Mountain region represented 5% of our PV-10 in the Rocky Mountain Region as of December 31, 2008 and 9% of our average daily Rocky Mountain Region Boe production for the three months ended December 31, 2008. During the three months ended December 31, 2008, we produced an average of 1,794 net Bbls of oil and 4,280 net Mcf of natural gas per day from our wells in the Big Horn Basin and other areas within the Rocky Mountain region.

Our principal property in the Big Horn Basin, the Worland field, produces primarily from the Phosphoria formation. We also have several other ongoing projects in the Rockies including conventional 3D defined Red River and Lodgepole structures in North Dakota and Montana, horizontal Fryburg opportunities in North Dakota and the Lewis Shale and Fort Union in Wyoming.

Conventional Red River. The Red River is a well known conventional producing oil and gas reservoir throughout the Williston Basin of North Dakota and Montana. The production can be quite prolific with individual Red River wells producing up to 1.5 million barrels of oil but the productive reservoir is generally confined to structural closures and structural-stratigraphic traps of 320 acres to 640 acres in size. The potential exists to find this type of conventional Red River production underlying any portion of our Bakken acreage in North Dakota and Montana. To identify these Red River traps generally requires 3D seismic. We own or have under license 964 square miles of 3D seismic over portions of our acreage in Montana and North Dakota. As of December 31, 2008 we had interpreted approximately 8% of this data using our proprietary processing techniques and have identified 9 undrilled potential locations. In 2008, we drilled and completed 6 gross (3.1 net) vertical Red River wells with 4 gross (2.2 net) wells completed as producers for a 71% success rate. During 2009, we plan to continue re-processing and evaluating our 3D seismic to identify new potential drilling locations.

Mid-Continent and Gulf Coast Region

Our properties in the Mid-Continent and Gulf Coast region represented 24% of our PV-10 as of December 31, 2008. During the three months ended December 31, 2008, our average daily production from such properties was 2,321 net Bbls of oil and 37,922 net Mcf of natural gas. Our principal producing properties in this region are located in the Anadarko and Arkoma Basins of Oklahoma, the Michigan Basin and the Illinois Basin.

Arkoma Woodford

The Arkoma Woodford play in Atoka, Coal, Hughes and Pittsburg Counties, Oklahoma has matured into one of the more active unconventional gas resource plays in the United States with 36 rigs drilling in the play industry wide as of December 31, 2008. We owned approximately 161,000 gross (47,000 net) acres in the Woodford play as of December 31, 2008. Since drilling our first well in February, 2006, we have completed a total of 259 gross (41.4 net) horizontal Woodford wells through December 31, 2008. These Arkoma Woodford wells represent 52% of the PV-10 in the Mid-Continent Region as of December 31, 2008 and 41% of our average daily Mid-Continent Region equivalent production for the three months ended December 31, 2008. During 2008, production from our Arkoma Woodford wells grew 213% from an average of 8,428 Mcf of natural gas equivalent per day during December 2007 to 26,380 Mcf of natural gas equivalent per day in December 2008.

We completed 115 gross (23.3 net) Woodford wells during 2008. This drilling consisted of a combination of exploratory, step-out and development drilling designed to secure acreage and delineate areas of economic production for further development. Of significance, we expanded the known extents of commercial production to the western extents of our Ashland AMI and south into our Big Mac Prospect. We also completed our first well in the East McAlester area. As of December 31, 2008, approximately 72% of our net acreage remained undeveloped.

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During the year ended December 31, 2008, we began to develop the field on various densities including 320, 160 and 80-acre spacing, to determine the optimum spacing for development. Results indicated that 80-acre development is economically feasible on much of our acreage. We also began simul-fracing wells when possible to more effectively stimulate and produce the Woodford shale while causing minimal disruption to existing production. We also reduced our average cost per lateral foot drilled by 20% compared to 2007 through improved mud systems, bit selections and operational efficiencies. We also successfully demonstrated that we can drill and complete wells across faults that previously limited the length of lateral drilled. To guide our drilling we acquired 49 square miles of 3-D seismic data during the year bringing the total of 3D seismic we own or have under license to 93 square miles.

We plan to invest approximately $56.0 million drilling 63 gross (8.0 net) horizontal wells in the Arkoma Woodford during 2009. We currently have one operated rig drilling in the play and are in the process of acquiring 53 square miles of 3-D seismic to guide future drilling on our East McAlester acreage.

Anadarko Basin

Our properties within the Anadarko Basin represented 27% of our PV-10 in the Mid-Continent Region as of December 31, 2008 and 40% of our average daily Mid-Continent Region equivalent production for the three months ended December 31, 2008. Our wells within the Anadarko Basin produce from a variety of sands and carbonates in both stratigraphic and structural traps. During the year we drilled 19 gross (11.5 net) wells with a 90% gross (84% net) success rate. In 2009, we plan to invest approximately $23.0 million in the drilling of 18 gross (5.0 net) wells in the Anadarko Basin.

Anadarko Woodford. We owned 189,246 gross (117,665 net) acres in the emerging Anadarko Woodford shale play of western Oklahoma as of December 31, 2008. This includes 144,000 gross (93,000 net) undeveloped acres acquired in 2008 and 44,923 gross (24,586 net) acres held by production. Our acreage is strategically positioned within the window of thermal maturation for natural gas along the eastern flank of the Anadarko basin extending across portions of Grady, Canadian, Blaine, Custer and Dewey Counties of Oklahoma. The Woodford shale underlying this acreage ranges from 75 to 250 feet thick and occurs at depth ranging from 10,000 to 15,000 feet. Industry peers began drilling and completing horizontal Woodford shale wells in Canadian County, Oklahoma in August of 2007 and as of December 31, 2008 there were 17 rigs drilling in the play. Results announced by various operators in the play have been encouraging, with initial daily production rates of up to 8,300 Mcf of natural gas equivalent per well. Based on our economic model, we expect to recover approximately 5 Bcf to 7 Bcf per well. During 2008 we drilled 2 gross (1.9 net) horizontal Woodford wells and both are currently in the process of being completed.

Anadarko Atoka. We owned 44,938 gross (27,566 net) acres in the emerging Anadarko Atoka Shale play of Western Oklahoma and the Panhandle of Texas as of December 31, 2008. Our acreage is focused in Ellis County, Oklahoma and Lipscomb County, Texas and strategically located along trend with the development of the Novi Lime formation. The Novi Lime formation is important as it serves as both reservoir and drilling conduit for the horizontal wellbore through which the surrounding natural gas charged Atoka shales can be fracture stimulated and produced. The Atoka shales range from 75 feet to 125 feet thick and are present throughout our properties. Public records show as of February 23, 2009, 37 horizontal Atoka wells have been completed by industry peers with initial production rates of up to 7,500 Mcf of natural gas per day. During 2008, we drilled 2 gross (2 net) horizontal Atoka wells. The first well, the Shrewder 1-22H (100% WI) completed flowing 1,297 Mcf of natural gas per day from a short, 1,300 foot, horizontal lateral. The second well, the Jones Trust 1-168H (100% WI) was recently fracture stimulated and currently flow testing at a rate of approximately 700 Mcf of natural gas per day.

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Illinois Basin

Our properties within the Illinois Basin represented 20.6% of the PV-10 in the Mid-Continent Region as of December 31, 2008 and 4.9% of our average daily Mid-Continent Region Boe production for the three months ended December 31, 2008. We drilled 19 gross (17 net) wells during 2008 developing fields and expanding our reserve base in the Illinois Basin. Our production within the Illinois Basin is primarily crude oil from units comprised of shallow sand formations under water injection.

Michigan Trenton-Black River

Our Trenton-Black River project in and around Hillsdale County, Michigan continues to produce excellent results guided by our proprietary 3-D seismic techniques. As of December 31, 2008, we had completed 7 gross (5.8 net) operated wells in the play with 6 gross (4.9 net) of the wells completed as Trenton-Black River producers and 1 gross (1 net) well temporarily abandoned. These 6 producing wells were assigned average estimated recoverable reserves of 490 MBoe per well. Combined, these wells were producing an average of 550 gross barrels of oil per day during the month of December 31, 2008. Three of the wells are capable of flowing in excess of the 200 barrels of oil per day allowable set by the Michigan Department of Environmental Quality and 3 are restricted by natural gas flaring restrictions which will be removed once the wells are connected to a natural gas pipeline. A natural gas gathering pipeline has been installed and processing facilities are under construction to enable these flare restricted wells to produce up to the 200 barrels of oil per day allowable rate.

We owned approximately 65,418 gross (52,110 net) acres in the play and have shot, processed and interpreted approximately 40 square mile of 3-D seismic on the acreage as of December 31, 2008. During 2008, we completed the acquisition of 20 square miles of 3-D seismic on our Chicago/Norad project. Interpretation of the seismic data identified up to 14 potential drilling locations. Four of these locations have been selected and permitted for drilling. We plan to acquire another 6.5 square miles of additional 3D seismic data during 2009.

Gulf Coast

During the three months ended December 31, 2008, our average daily production from our Gulf Coast properties was 225 net Bbls of oil and 2,341 net Mcf of natural gas. Our principal producing properties in this region are located in South Texas and Louisiana.

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, 2008, 2007 and 2006:

	Year Ended December 31,		
	2008	**2007**	**2006**
Net production volumes:			
Oil (MBbls)[1]	9,147	8,699	7,480
Natural gas (MMcf)	17,151	11,534	9,225
Oil equivalents (MBoe)	12,006	10,621	9,018
Average prices[1]:			
Oil ($/Bbl)	$ 88.87	$ 63.55	$ 55.30
Natural gas ($/Mcf)	6.90	5.87	6.08
Oil equivalents ($/Boe)	77.66	58.31	52.09
Costs and expenses[1]:			
Production expense ($/Boe)	$ 8.40	$ 7.35	$ 6.99
Production tax ($/Boe)	4.84	3.13	2.48
General and administrative expense ($/Boe)	2.95	3.15	3.45
DD&A expense ($/Boe)	12.30	9.00	7.27

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(1) Oil sales volumes were 97 MBbls more than production volumes for the year ended December 31, 2008 due to the sale of temporarily stored barrels. Oil sales volumes were 221 MBbls and 21 MBbls less than oil production volumes for the years ended December 31, 2007 and 2006, respectively, due to temporary storage and pipeline line fill. Average prices and per unit costs have been calculated using sales volumes.

The following table sets forth information regarding our average daily production during the fourth quarter of 2008:

	Fourth Quarter 2008		
	Oil (Bbls)	Gas (Mcf)	Total (Boe)
Rockies:			
Red River units	12,860	7,187	14,058
Bakken field			
Montana Bakken	5,697	4,278	6,410
North Dakota Bakken	4,185	1,296	4,401
Other	1,794	4,280	2,507
Mid-Continent:			
Arkoma Woodford	50	19,353	3,276
Other	2,046	16,228	4,751
Gulf Coast	225	2,341	615
Total	26,857	54,963	36,018

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, 2008:

	Oil Wells		Natural Gas Wells		Total Wells	
	Gross	Net	Gross	Net	Gross	Net
Rockies:						
Red River units	265	240	2	2	267	242
Bakken field						
Montana Bakken	151	98	3	2	154	100
North Dakota Bakken	144	46	5	1	149	47
Other	305	271	6	2	311	273
Mid-Continent:						
Arkoma Woodford			259	41	259	41
Other	777	622	243	131	1,020	753
Gulf Coast	5	4	27	13	32	17
Total	1,647	1,281	545	192	2,192	1,473

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, 2008, we owned interests in no wells containing multiple completions.

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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 endeavor to 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 revolving 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.

Marketing and Major Customers

We primarily sell our oil production to end users at major market centers. Other production is sold to select midstream marketing companies or oil refining companies at the lease. We have significant production directly connected to a pipeline gathering system, although the balance of our production is transported by truck. Where the oil that is directly marketed is transported by truck, the oil is delivered to the most practical point on a pipeline system for delivery to a sales point downstream on another connecting pipeline. Oil that is sold at the lease is delivered directly onto the purchasers truck and the sale is complete at that point.

During the fourth quarter of 2007 and various periods in 2008, we were unable to market some of our Rocky Mountain area crude at a price acceptable to us. This resulted in increases in our crude oil inventory at various times throughout the year. The prices we were offered were adversely affected by seasonal demand and by pipeline constraints. At various times during 2007 and 2008, we shipped some of our Rocky Mountain crude by railcar to help alleviate this situation and obtain more favorable prices. 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, 2008, oil sales to Marathon Oil Company accounted for 44% of our total revenue. No other purchasers accounted for more than 10% of our total oil and gas sales. 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.

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 and access 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. 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 who are similarly situated.

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 prorating 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 similarly situated competitors.

Regulation of Transportation and Sales of Natural Gas

Historically, the transportation and sale for resale of natural gas in interstate commerce have been regulated by agencies of the U.S. federal government, primarily 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 and culminated in adoption of the Natural Gas Wellhead Decontrol Act which removed 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 a series of orders to implement its open access policies. As a result, 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.

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.

The price at which we sell natural gas is not currently subject to federal rate regulation and, for the most part, is not subject to state regulation. However, with regard to our physical sales of these energy commodities, we are required to observe anti-market manipulation laws and related regulations enforced by the FERC and/or the Commodity Futures Trading Commission (CFTC). See below the discussion of Other Federal Laws and Regulations Affecting Our Industry Energy Policy Act of 2005. Should we violate the anti-market manipulation laws and regulations, we could also be subject to related third party damage claims by, among others, sellers, royalty owners and taxing authorities. In addition, pursuant to Order 704, some of our operations may be required to annually report to FERC, starting May 1, 2009, information regarding natural gas sale transactions depending on the volume of natural gas transacted during the prior calendar year. See below the discussion of Other Federal Laws and Regulations Affecting Our Industry FERC Market Transparency Rules.

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. State regulation of natural gas gathering facilities generally include various safety, environmental and, in some circumstances, nondiscriminatory take requirements. Although such regulation has not generally been affirmatively applied by state agencies, natural gas gathering may receive greater regulatory scrutiny in the future.

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

Regulation of Production

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

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

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Other Federal Laws and Regulations Affecting Our Industry

Energy Policy Act of 2005. On August 8, 2005, President Bush signed into law the Domenici-Barton Energy Policy Act of 2005 (EP Act 2005). The EP Act 2005 is a comprehensive compilation of tax incentives, authorized appropriations for grants and guaranteed loans, and significant changes to the statutory policy that affects all segments of the energy industry. Among other matters, EP Act 2005 amends the NGA to add an anti- market manipulation provision which makes it unlawful for any entity to engage in prohibited behavior to be prescribed by FERC, and furthermore provides FERC with additional civil penalty authority. The EP Act 2005 provides the FERC with the power to assess civil penalties of up to $1,000,000 per day for violations of the NGA and increases the FERC s civil penalty authority under the NGPA from $5,000 per violation per day to $1,000,000 per violation per day. The civil penalty provisions are applicable to entities that engage in the sale of natural gas for resale in interstate commerce. On January 19, 2006, FERC issued Order No. 670, a rule implementing the anti-market manipulation provision of EP Act 2005, and subsequently denied rehearing. The rules make it unlawful to: (1) in connection with the purchase or sale of natural gas subject to the jurisdiction of FERC, or the purchase or sale of transportation services subject to the jurisdiction of FERC, for any entity, directly or indirectly, to use or employ any device, scheme or artifice to defraud; (2) to make any untrue statement of material fact or omit to make any such statement necessary to make the statements made not misleading; or (3) to engage in any act or practice that operates as a fraud or deceit upon any person. The new anti-market manipulation rule does not apply to activities that relate only to intrastate or other non-jurisdictional sales or gathering, but does apply to activities of gas pipelines and storage companies that provide interstate services, as well as otherwise non-jurisdictional entities to the extent the activities are conducted in connection with gas sales, purchases or transportation subject to FERC jurisdiction, which now includes the annual reporting requirements under Order 704. The anti-market manipulation rule and enhanced civil penalty authority reflect an expansion of FERC s NGA enforcement authority.

FERC Market Transparency Rules. On December 26, 2007, FERC issued a final rule on the annual natural gas transaction reporting requirements, as amended by subsequent orders on rehearing (Order 704). Under Order 704, wholesale buyers and sellers of more than 2.2 million MMBtu of physical natural gas in the previous calendar year, including interstate and intrastate natural gas pipelines, natural gas gatherers, natural gas processors, natural gas marketers, and natural gas producers, are now required to report, on May 1 of each year beginning in 2009, aggregate volumes of natural gas purchased or sold at wholesale in the prior calendar year to the extent such transactions utilize, contribute to, or may contribute to the formation of price indices. It is the responsibility of the reporting entity to determine which individual transactions should be reported based on the guidance of Order 704. Order 704 also requires market participants to indicate whether they report prices to any index publishers, and if so, whether their reporting complies with FERC s policy statement on price reporting.

Additional proposals and proceedings that might affect the natural gas industry are pending before Congress, FERC and the courts. We cannot predict the ultimate impact of these or the above regulatory changes to our natural gas operations. We do not believe that we would be affected by any such FERC action materially differently than similarly situated competitors.

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 including areas containing endangered specie of plants and animals; and

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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, cleanup and remediation requirements for the oil and gas industry could have a significant impact on our operating costs.

Some of the existing environmental, health and safety laws and regulations to which our business operations are subject include, among others, (i) regulations by the EPA and various state agencies regarding approved methods of disposal for certain hazardous and nonhazardous wastes; (ii) the Comprehensive Environmental Response, Compensation, and Liability Act and analogous state laws that may require the removal of previously disposed wastes (including wastes disposed of or released by prior owners or operators), property contamination (including groundwater contamination), and remedial plugging operations to prevent future contamination; (iii) the Clean Air Act and comparable state and local requirements, which establish pollution control requirements with respect to air emissions from our operations; (iv) the Oil Pollution Act of 1990, which contains numerous requirements relating to the prevention of and response to oil spills into waters of the United States; (v) the Federal Water Pollution Control Act, or the Clean Water Act, and analogous state laws which 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; (vi) the Resource Conservation and Recovery Act, which is the principal federal statute governing the treatment, storage and disposal of hazardous wastes and comparable state law pertaining to the handling of solid and hazardous wastes; (vii) the Safe Drinking Water Act and analogous state laws which impose requirements relating to our underground injection activities; (viii) the National Environmental Policy Act, which requires federal agencies, including the Department of Interior, to evaluate major agency actions that have the potential to significantly impact the environment; (ix) the federal Occupational Safety and Health Act and comparable state statutes which require that we organize and/or disclose information about hazardous materials stored, used or produced in our operations and; (x) state regulations and statutes governing the handling, treatment, storage and disposal of naturally occurring radioactive material.

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 itemized. Although we believe that our continued compliance with existing requirements will not have a material adverse impact on our financial condition and results of operations, we cannot assure you that the passage of more stringent laws or regulations in the future will not have a negative impact on our financial position or results of operations.

Employees

As of December 31, 2008, we employed 394 people, including 209 employees in drilling and production, 58 in financial and accounting, 36 in land, 28 in exploration, 13 in reservoir engineering, 39 in administrative and 11 in information technology. Our future success will depend partially on our ability to attract, retain and motivate qualified personnel. We are not a party to any collective bargaining agreements and have not experienced any strikes or work stoppages. We consider our relations with our employees to be satisfactory. We utilize the services of independent contractors to perform various field and other services.

Initial Public Offering

On May 14, 2007, we completed our initial public offering. In conjunction therewith, we effected an 11 for 1 stock split by means of a stock dividend. All prior period share and per share information contained in this report have been retroactively restated to give effect to the stock split. On May 14, 2007, we amended our certificate of incorporation to, among other things, increase the number of authorized preferred shares to 25 million and common shares to 500 million. Prior to completion of our initial public offering, we were a subchapter S corporation and income taxes were payable by our shareholders. In connection with the public offering, we converted to a subchapter C corporation and recorded a charge to earnings in the second quarter of 2007 of $198.4 million to recognize deferred taxes at May 14, 2007. Thereafter, we have provided for income taxes on income. See *Notes to Consolidated Financial Statements Note 1. Organization and Summary of Significant Accounting Policies Pro forma information (unaudited) and Income taxes and Note 12. Shareholders Equity* for a complete discussion of the accounting for the various transactions resulting from our initial public offering and of the pro forma information presented.

Company Contact Information

Our corporate internet web site is *www.contres.com.* Through the investor relations section of our website, we make available our annual report on Form 10-K, quarterly reports on Form 10-Q, current reports on Form 8-K, and all amendments to those reports as soon as reasonably practicable after the report is filed with or furnished to the Securities and Exchange Commission. For a current version of various corporate governance documents, including our Code of Ethics (as updated February 25, 2009), please see our website. Information contained at our website is not incorporated by reference into this report and you should not consider information contained at our website as part of this report.

We file periodic reports and proxy statements with the Securities and Exchange Commission (SEC). The public may read and copy any materials we file with the SEC at the SEC s Public Reference Room at 100 F Street N.E., Washington, D.C. 20549. The public may obtain information about the operation of the Public Reference Room by calling the SEC at 1-800-SEC-0330. We file our reports with the SEC electronically. The SEC maintains an Internet site that contains reports, proxy and information statements, and other information regarding issuers that file electronically with the SEC. The address of this site is http://www.sec.gov.

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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Item 1A. Risk Factors

You should carefully consider each of the risks described below, together with all of the other information contained in this report, 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:

- worldwide and regional economic conditions impacting the global supply and demand for oil and natural gas;
- the actions of the Organization of Petroleum Exporting Countries, or OPEC;
- the price and quantity of imports of foreign oil and natural gas;
- political conditions in or affecting other oil-producing and natural gas-producing countries, including the current conflicts in the Middle East and conditions in South America and Russia;
- the level of global oil and natural gas exploration and production;
- the level of global oil and natural gas inventories;
- localized supply and demand fundamentals and transportation availability;
- weather conditions;
- technological advances affecting energy consumption; and
- the price and availability of alternative fuels.

Furthermore, the current worldwide financial and credit crisis has reduced the availability of liquidity and credit to fund the continuation and expansion of industrial business operations worldwide. The shortage of liquidity and credit combined with recent substantial losses in worldwide equity markets has lead to a worldwide economic recession. The slowdown in economic activity caused by such recession has reduced worldwide demand for energy and resulted in lower oil and natural gas prices. Oil prices declined from record high levels in early July 2008 of over $140 per Bbl to below $35 per Bbl in February 2009, while natural gas prices declined from over $13 per Mcf to approximately $4 per Mcf over the same period.

Lower oil and natural gas prices will reduce our cash flows and borrowing ability. For example, although our average realized price received for oil and natural gas was $77.66 per Boe for the year ended December 31, 2008, it was bolstered by record oil prices for the first half of the year. In the fourth quarter of 2008, our average realized price received for oil and natural gas declined to $38.80 per Boe. See - Our exploration, 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. Lower oil and natural gas prices may also reduce the amount of oil and natural gas that we can produce economically.

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

In addition, because our producing properties are geographically concentrated in the Rocky Mountain region, we are vulnerable to fluctuations in pricing in that area. In particular, 76% of our production during the fourth quarter of 2008 was from the Rocky Mountain region. As a result of this concentration, we may be disproportionately exposed to the impact of regional supply and demand factors, transportation capacity constraints, curtailment of production or interruption of transportation of oil produced from the wells in these areas. Such factors can cause significant fluctuation in our realized oil and natural gas prices. For example, the difference between the average NYMEX oil price and our average realized oil price for the year ended December 31, 2008 was $9.50 per Bbl, whereas the difference between the NYMEX oil price and our realized oil price for the year ended December 31, 2007 was $8.85 per Bbl.

Our exploration, 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. Our cash flow used in investing activities was $930.8 million related to capital and exploration expenditures in 2008. Our budgeted capital expenditures for 2009 are expected to be approximately $275.0 million with $211.0 million allocated for drilling and completion operations. To date, these capital expenditures have been financed with cash generated by operations and through borrowings under our revolving credit facility. The actual amount and timing of our future capital expenditures may differ materially from our estimates as a result of, among other things, commodity prices, actual drilling results, the availability of drilling rigs and other services and equipment, and regulatory, technological and competitive developments. We expect to manage capital expenditures for 2009 to be inline with our cash flows from operations, and expect our capital expenditures during 2009 to be significantly lower than our 2008 capital expenditures due to our desire to cut back on spending due to the current economic crisis and steep drop in oil and natural gas prices. Continued weakness in commodity prices may result in a decrease in our actual capital expenditures. Conversely, a significant improvement in product prices could result in an increase in our capital expenditures. 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 or the sale of assets. The issuance of additional debt may 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;
- our ability to acquire, locate and produce new reserves; and
- the ability of our banks to lend.

If our revenues or the borrowing base under our revolving credit facility decrease as a result of lower oil or natural gas prices, operating difficulties, declines in reserves or for any other reason, we may have limited ability

to obtain the capital necessary to sustain our operations at current levels. If additional capital is needed, we may not be able to obtain debt or equity financing. If cash generated by operations or cash available under our revolving credit facility is not sufficient to meet our capital requirements, the failure to obtain additional financing could result in a curtailment of our operations relating to development of our prospects, which in turn could lead to a decline in our oil and natural gas reserves, and could adversely affect our business, financial condition and results of operations.

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

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

Further, many factors may curtail, delay or cancel our scheduled drilling projects, 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 blizzards and ice storms;
- reductions in oil and natural gas prices;
- limited availability of financing at acceptable rates;
- 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 current and future economic conditions and commodity prices. Any significant inaccuracies in these interpretations or assumptions could materially affect our estimated quantities and present value of our reserves. See Item 1. Business Proved

Reserves for information about our estimated oil and natural gas reserves and the PV-10 and standardized measure of discounted future net cash flows as of December 31, 2008.

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 will vary from our estimates. Any significant

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variance could materially affect the estimated quantities and present value of our reserves. 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.

You should not assume that the present value of future net revenues from our proved reserves 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, 2008 would decrease approximately $47 million. If natural gas prices decline by $0.10 per Mcf, then our PV-10 as of December 31, 2008 would decrease approximately $8 million.

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

One of our business strategies is to commercially develop unconventional oil and natural gas resource plays using enhanced recovery technologies. For example, 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.

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

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

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

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 cause us to incur significant expenditures that are not provided for in our capital budget, 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. Additionally 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, explosions and ruptures of pipelines in connection with our high-pressure air injection operations;
- personal injuries and death; and
- natural disasters.

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

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

We may elect not to obtain insurance if we believe that the cost of available insurance is excessive relative to the risks presented. In addition, pollution and environmental risks generally are not fully insurable. The occurrence of an event that is not fully covered by insurance could have a material adverse effect on our business, financial condition and results of operations.

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

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

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

Our management has specifically identified and scheduled drilling locations as an estimation of our future multi-year drilling activities on our existing acreage. These 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. The North Dakota Bakken Shale and Arkoma Woodford projects comprise the majority of these drilling locations. Due to limited production history on the relatively few number of wells drilled in these projects, we are unable to predict with certainty the quantity of future production from wells to be drilled in these projects. If future drilling results in these projects do not establish sufficient reserves to achieve an economic return, we may curtail drilling in these projects. 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, 2008, we had leases representing 152,105 net acres expiring in 2009, 221,522 net acres expiring in 2010, and 360,123 net acres expiring in 2011. 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. In addition, if gas quality specifications for the third party natural gas pipelines with which we connect change so as to restrict our ability to transport natural gas, our access to natural gas markets could be impeded. If our production becomes shut in for any of these or other reasons, we would be unable to realize revenue from those wells until other arrangements were made to deliver the products to market.

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

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

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

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

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existing laws and regulations. In addition, our costs of compliance may increase if existing laws and regulations are revised or reinterpreted, or if new laws and regulations become applicable to our operations. Such costs could have a material adverse effect on our business, financial condition and results of operations.

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

Strict, joint and several liabilities 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. In addition, claims for damages to persons or property, including natural resources, may result from our operations.

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.

Should we fail to comply with all applicable FERC administered statutes, rules, regulations and orders, we could be subject to substantial penalties and fines.

Under the EP Act 2005, FERC has civil penalty authority under the NGA to impose penalties for current violations of up to $1 million per day for each violation and disgorgement of profits associated with any violation. While our systems have not been regulated by FERC as a natural gas company under the NGA, FERC has adopted regulations that may subject certain of our otherwise non-FERC jurisdictional facilities to FERC annual reporting and daily scheduled flow and capacity posting requirements. Additional rules and legislation pertaining to those and other matters may be considered or adopted by FERC from time to time. Failure to comply with those regulations in the future could subject Continental to civil penalty liability.

Our operations may incur substantial liabilities in connection with climate change legislation and regulatory initiatives.

Recent scientific studies have suggested that emissions of certain gases, commonly referred to as greenhouse gases and including carbon dioxide and methane, may be contributing to warming of the Earth s atmosphere. In response to such studies, the U.S. Congress is considering legislation to reduce emissions of greenhouse gases and more than one-third of the states, either individually or through multi-state initiatives, already have begun implementing legal measures to reduce emissions of greenhouse gases. Also, the U.S. Supreme Court s holding in its 2007 decision, *Massachusetts, et al. v. EPA*, that carbon dioxide may be regulated as an air pollutant under the federal Clean Air Act could result in future regulation of greenhouse gas emissions from stationary sources, even if Congress does not adopt new legislation specifically addressing emissions of greenhouse gases. In July 2008, EPA released an Advance Notice of Proposed Rulemaking regarding possible future regulation of greenhouse gas emissions under the Clean Air Act. Although the notice did not propose any specific, new regulatory requirements for greenhouse gases, it indicates that federal regulation of greenhouse gas emissions could occur in the near future. Although it is not possible at this time to predict how legislation or new regulations that may be adopted to address greenhouse gas emissions would impact our business, any such future laws and regulations could result in increased compliance costs or additional operating restrictions, and could have an adverse effect on our business or demand for the oil and natural gas we produce.

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

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 for acquiring properties, marketing oil and natural gas and securing trained personnel. Also, there is substantial competition for capital available for investment in the oil and natural gas industry. Many of our competitors possess and employ financial, technical and personnel resources substantially greater than ours. 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, companies may be able to offer better compensation packages to attract and retain qualified personnel than we are able to offer. The cost to attract and retain qualified personnel has increased over the past three years due to competition and may increase substantially in the future. 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, which could have a material adverse effect on our business.

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

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, President 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.

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, 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 revolving 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 revolving 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 revolving 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 revolving 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 revolving 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 revolving 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 revolving credit facility, together with accrued interest, to be due and payable. If we were unable to repay such borrowings or interest, our lenders could proceed against their collateral. If the indebtedness under our revolving credit facility were to be accelerated, our assets may not be sufficient to repay in full such indebtedness.

Increases in interest rates could adversely affect our business.

Our business and operating results can be harmed by factors such as the availability, terms of and cost of capital, increases in interest rates or a reduction in credit rating. These changes could cause our cost of doing business to increase, limit our ability to pursue acquisition opportunities, reduce cash flow used for drilling and place us at a competitive disadvantage. For example, as of February 23, 2009, outstanding borrowings under our revolving credit facility were $474.4 million and the impact of a 1% increase in interest rates on this amount of debt would result in increased interest expense of approximately $4.7 million and a $2.9 million decrease in our net income. Recent and continuing disruptions and volatility in the global financial markets may lead to a contraction in credit availability impacting our ability to finance our operations. We require continued access to capital. A significant reduction in cash flows from operations or the availability of credit could materially and adversely affect our ability to achieve our planned growth and operating results.

The continuing financial crisis may impact our business and financial condition. We may not be able to obtain funding in the capital markets on terms we find acceptable, or obtain funding under our current revolving credit facility because of the deterioration of the capital and credit markets and our borrowing base.

The current credit crisis and related turmoil in the global financial systems have had an impact on our business and our financial condition, and we may face challenges if economic and financial market conditions do not improve. Historically, we have used our cash flow from operations and borrowings under our revolving credit facility to fund our capital expenditures and have relied on the capital markets and asset monetization transactions to provide us with additional capital for large or exceptional transactions. A continuation of the economic crisis could further reduce the demand for oil and natural gas and continue to put downward pressure on the prices for oil and natural gas, which have declined significantly since reaching historic highs in July 2008. These price declines have negatively impacted our revenues and cash flows.

We have an existing revolving credit facility with lender commitments totaling $672.5 million. In the future, we may not be able to access adequate funding under our bank credit facilities as a result of (i) a decrease in our borrowing base due to the outcome of a subsequent borrowing base redetermination, or (ii) an unwillingness or inability on the part of our lending counterparties to meet their funding obligations. The recent declines in commodity prices, or a continuing decline in those prices, could result in a determination to lower the borrowing base in the future and, in such case, we could be required to repay any indebtedness in excess of the borrowing base. The turmoil in the financial markets has adversely impacted the stability and solvency of a number of large global financial institutions.

The current credit crisis makes it difficult to obtain funding in the public and private capital markets. In particular, the cost of raising money in the debt and equity capital markets has increased substantially while the availability of funds from those markets generally has diminished significantly. Also, as a result of concerns about the general stability of financial markets and the solvency of specific counterparties, the cost of obtaining money from the credit markets has increased as many lenders and institutional investors have increased interest rates, imposed tighter lending standards, refused to refinance existing debt at maturity at all or on terms similar to existing debt or at all, and reduced and, in some cases, ceased to provide any new funding.

The credit crisis also has impacted the level of activity in the oil and natural gas property sales market. The lack of available credit and access to capital has limited and will likely continue to limit the parties interested in any proposed asset transactions and will likely reduce the values we could realize in those transactions.

Due to these factors, we cannot be certain that funding, if needed, will be available to the extent required and on acceptable terms. If we are unable to access funding when needed on acceptable terms, we may not be able to fully implement our business plans, complete new property acquisitions to replace our reserves, take advantage of business opportunities, respond to competitive pressures, or refinance our debt obligations as they come due, any of which could have a material adverse effect on our operations and financial results.

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

Our principal exposures to credit risk are through joint interest receivables ($156.6 million at December 31, 2008) and the sale of our oil and natural gas production ($72.4 million in receivables at December 31, 2008), which we market to energy marketing companies, refineries and affiliates. Joint interest receivables arise from billing entities who own partial interest in the wells we operate. These entities participate in our wells primarily based on their ownership in leases on which we wish to drill. We can do very little to choose who participates in our wells. We are also subject to credit risk due to concentration of our oil and natural gas receivables with several significant customers. The largest purchaser of our oil and natural gas, during the twelve months ended December 31, 2008, accounted for 44% of our total revenues. We do not require our customers to post collateral. The inability or failure of our significant customers to meet their obligations to us or their insolvency or liquidation may adversely affect our financial results.

Our derivative activities could result in financial losses or could reduce our earnings.

To achieve a more predictable cash flow and to reduce our exposure to adverse fluctuations in the prices of oil and natural gas, we on occasion, enter into derivative instruments for a portion of our oil and/or natural gas production, including collars and price-fix swaps. In July 2007, we entered into fixed price swaps covering 10,000 barrels of oil per day for August 2007 through April 2008 at a price of $72.90 per barrel. We did not designate any of our derivative instruments as hedges for accounting purposes and did record all derivative instruments on our balance sheet at fair value. Changes in the fair value of our derivative instruments were recognized in current earnings. Accordingly, our earnings may fluctuate significantly as a result of changes in fair value of our derivative instruments.

Derivative instruments also expose us to the risk of financial loss in some circumstances, including when:

- production is less than the volume covered by the derivative instruments;
- the counter-party to the derivative instrument defaults on its contract obligations; or
- there is an increase in the differential between the underlying price in the derivative instrument and actual prices received.

In addition, these types of derivative arrangements limit the benefit we would receive from increases in the prices for oil and natural gas.

We may be subject to risks in connection with acquisitions.

The successful acquisition of producing properties requires an assessment of several factors, including:

- recoverable reserves;
- future oil and natural gas prices and their appropriate differentials;

operating costs; and

potential environmental and other liabilities.

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The accuracy of these assessments is inherently uncertain. In connection with these assessments, we perform a review of the subject properties that we believe to be generally consistent with industry practices. Our review will not reveal all existing or potential problems nor will it permit us to become sufficiently familiar with the properties to fully assess their deficiencies and capabilities. Inspections may not always be performed on every well, and environmental problems are not necessarily observable even when an inspection is undertaken. Even when problems are identified, the seller may be unwilling or unable to provide effective contractual protection against all or part of the problems. We often are not entitled to contractual indemnification for environmental liabilities and acquire properties on an as is basis.

Our business depends on oil and natural gas transportation facilities, most of which are owned by third parties.

The marketability of our oil and natural gas production depends in part on the availability, proximity and capacity of pipeline systems owned by third parties. The unavailability of, or lack of, available capacity on these systems and facilities could result in the shut-in of producing wells or the delay, or discontinuance of, development plans for properties. Although we have some contractual control over the transportation of our product, material changes in these business relationships could materially affect our operations. We generally do not purchase firm transportation on third party facilities and therefore, our production transportation can be interrupted by those having firm arrangements. Federal and state regulation of oil and natural gas production and transportation, tax and energy policies, changes in supply and demand, pipeline pressures, damage to or destruction of pipelines and general economic conditions could adversely affect our ability to produce, gather and transport oil and natural gas.

The disruption of third-party facilities due to maintenance and/or weather could negatively impact our ability to market and deliver our products. We have no control over when or if such facilities are restored or what prices will be charged. A total shut-in of production could materially affect us due to a lack of cash flow, and if a substantial portion of the production is hedged at lower than market prices, those financial hedges would have to be paid from borrowings absent sufficient cash flow.

Our Chairman and Chief Executive Officer owns approximately 72.8% of our outstanding common stock, giving him influence and control in corporate transactions and other matters, including a sale of our company.

As of February 23, 2009, Harold G. Hamm, our Chairman, President and Chief Executive Officer, beneficially owns 123,458,708 shares of our outstanding common stock representing approximately 72.8% of our outstanding common shares. 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.

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Item 1B. Unresolved Staff Comments

There were no unresolved Securities and Exchange Commission staff comments at December 31, 2008.

Item 2. Properties

The information required by Item 2 is contained in Item 1. Business Oil and Gas Operations .

Item 3. 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.

Item 4. Submission of Matters to a Vote of Security Holders

There were no matters submitted to a vote of security holders during the fourth quarter of 2008.

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Part II

Item 5. Market for Registrant s Common Equity and Related Shareholder Matters

Our common stock is listed on the New York Stock Exchange and trades under the symbol CLR. The following table sets forth quarterly high and low sales prices since May 14, 2007, when we became a publicly traded company, and cash dividends declared for each quarter of the previous two years.

	2008				2007			
	First Quarter	Second Quarter	Third Quarter	Fourth Quarter	First Quarter	Second Quarter	Third Quarter	Fourth Quarter
High	$ 32.06	$ 76.10	$ 83.81	$ 39.74	$	$ 16.40	$ 18.97	$ 27.62
Low	20.55	30.55	31.44	12.01		14.00	14.11	18.05
Cash Dividend					0.12	0.21		

We declared cash dividends to our shareholders of record for tax purposes and, subject to forfeiture, to holders of unvested restricted stock during such time as we were a subchapter S corporation. On January 10, 2007, we declared a cash dividend of approximately $18.8 million to our shareholders for tax purposes and, subject to forfeiture, to holders of unvested restricted stock. On January 31, 2007, we paid $18.7 million of the dividend declared. On March 6, 2007, we declared a cash dividend of approximately $33.3 million payable in April 2007 to our shareholders of record as of March 15, 2007, for tax purposes and, subject to forfeiture, to holders of unvested restricted stock. In connection with the completion of our offering on May 14, 2007, we converted 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. As of February 23, 2009, the number of record holders of our common stock was 54. Management believes, after inquiry, that the number of beneficial owners of our common stock is approximately 28,000. On February 23, 2009, the last reported sales price of our Common Stock, as reported on the NYSE, was $15.18 per share.

The following table summarizes our purchases of our common stock during the fourth quarter of 2008:

Period	(a) Total number of shares purchased	(b) Average price paid per share	(c) Total number of shares purchased as part of publicly announced plans or programs	(d) Maximum number of shares that may yet be purchased under the plans or program
October 1, 2008 to October 31, 2008	60,295	$ 29.28		
November 1, 2008 to November 30, 2008	14,214	$ 26.37		
December 1, 2008 to December 31, 2008	14,722	$ 17.94		
Total	89,231	$ 26.94		

All shares purchased above represent shares issued pursuant to stock option exercises or restricted stock grants that were surrendered to cover taxes required to be withheld. We paid the amounts above to the Internal Revenue Service for the required withholding. See *Notes to Consolidated Financial Statements Note 13. Stock Compensation.*

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Performance Graph

The information provided in this section is being furnished to, and not filed with, the SEC. As such, this information is neither subject to Regulation 14A or 14C nor to the liabilities of Section 18 of the Securities Exchange Act of 1934, as amended. As required by these rules, the performance graph was prepared based upon the following assumptions:

- $100 was invested in our common stock at its initial public offering price of $15 per share and invested in the S&P 500 Index and our peer group on May 14, 2007, our initial public offering date, at the closing price on such date;

- investment in our peer group was weighted based on the stock price of each individual company within the peer group at the beginning of the period; and

- dividends were reinvested on the relevant payment dates.

Our peer group is comprised of Bill Barrett Corporation, Denbury Resources, Inc., Encore Acquisition Company, Quicksilver Resources, Inc., Range Resources Corp., Southwestern Energy Company and St. Mary Land and Exploration Company. We selected these companies because they are publicly traded exploration and production companies similar in size and operations to us.

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Item 6. Selected Financial Data

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, 2004 through 2008, has been derived from our audited historical consolidated financial statements for such periods. You should read the following selected historical consolidated financial data in connection with Management s Discussion and Analysis of Financial Condition and Results of Operation and our historical consolidated financial statements and related notes included elsewhere in this report. The selected historical consolidated results are not necessarily indicative of results to be expected in future periods.

	YEAR ENDED DECEMBER 31,				
	2008	2007	2006	2005	2004
Statement of Income:					
(in thousands, except per share data)					
Oil and natural gas sales[1]	$ 939,906	$ 606,514	$ 468,602	$ 361,833	$ 181,435
Derivative losses[1]	(7,966)	(44,869)			
Total revenues	960,490	582,215	483,652	375,764	418,910
Income from continuing operations	320,950	28,580	253,088	194,307	26,816
Net Income	320,950	28,580	253,088	194,307	27,864
Basic earnings per share:					
From continuing operations	$ 1.91	$ 0.17	$ 1.60	$ 1.23	$ 0.18
Net income per share	$ 1.91	$ 0.17	$ 1.60	$ 1.23	$ 0.18
Shares used in basic earnings per share	168,087	164,059	158,114	158,059	158,059
Diluted earnings per share:					
From continuing operations	$ 1.89	$ 0.17	$ 1.59	$ 1.22	$ 0.18
Net income per share	$ 1.89	$ 0.17	$ 1.59	$ 1.22	$ 0.18
Shares used in diluted earnings per share	169,392	165,422	159,665	159,307	159,236
Pro forma C-corporation[2]					
Pro forma income from continuing operations		$ 184,002	$ 156,833	$ 121,177	$ 16,626
Pro forma net income		184,002	156,833	121,177	17,276
Pro forma basic earnings per share		1.12	0.97	0.77	0.11
Pro forma diluted earnings per share		1.11	0.96	0.76	0.11
Production[3]					
Oil (MBbl)	9,147	8,699	7,480	5,708	3,688
Gas (MMcf)	17,151	11,534	9,225	9,006	8,794
Oil equivalent (MBoe)	12,006	10,621	9,018	7,209	5,154
Average sales prices[4]					
Oil ($/Bbl)	$ 88.87	$ 63.55	$ 55.30	$ 52.45	$ 37.12
Gas ($/Mcf)	6.90	5.87	6.08	6.93	5.06
Oil equivalent ($/Boe)	77.66	58.31	52.09	50.19	35.20
Average costs per Boe ($/Bbl)[5]					
Production expense	$ 8.40	$ 7.35	$ 6.99	$ 7.32	$ 8.49
Production tax	4.84	3.13	2.48	2.22	2.39
Depreciation, depletion, amortization and accretion	12.30	9.00	7.27	6.91	7.49
General and administrative	2.95	3.15	3.45	4.34	2.41
Proved reserves at December 31					
Oil (MBbl)	106,239	104,145	98,038	98,645	80,602
Gas (MMcf)	318,138	182,819	121,865	108,118	60,620
Oil equivalent (MBoe)	159,262	134,615	118,349	116,665	90,705
Other financial data (in thousands):					
Cash dividends per share	$	$ 0.33	$ 0.55	$ 0.01	$ 0.09
EBITDAX[6]	757,708	469,885	372,115	285,344	116,498
Net cash provided by operations	719,915	390,648	417,041	265,265	93,854
Net cash used in investing	(927,617)	(483,498)	(324,523)	(133,716)	(72,992)
Net cash provided by (used in) financing	204,170	94,568	(91,451)	(141,467)	(7,245)
Capital expenditures	988,593	525,677	326,579	144,800	94,307

Balance sheet data at December 31 (in thousands):					
Total assets	$ 2,215,879	$ 1,365,173	$ 858,929	$ 600,234	$ 504,951
Long-term debt, including current maturities	376,400	165,000	140,000	143,000	290,522
Shareholders equity	948,708	623,132	490,461	324,730	130,385

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(1) Oil and natural gas sales for the year ended December 31, 2004 are shown net of derivative loss accounted for as hedges of $6.4 million. Derivative losses in 2007 and 2008 were not accounted for as hedges and therefore are shown separately.

(2) Prior to our initial public offering, we were a subchapter S corporation and income taxes were payable by our shareholders and as a result, there was a minimal provision for income taxes for the periods ended December 31, 2006 and prior. See *Notes to Consolidated Financial Statements Note 1. Organization and Summary of Significant Accounting Policies Income taxes*. In connection with our initial public offering, we converted to a subchapter C corporation. Pro forma adjustments are reflected to provide for income taxes in accordance with SFAS No. 109 as if we had been a subchapter C corporation for all periods presented. A statutory Federal tax rate of 35% and effective state tax rate of 3% (net of Federal income tax effects) were used for the pro forma enacted tax rate for all pro forma periods presented.

(3) For the year 2008, oil sales volumes were 97 MBbls more than oil production volumes. For the years 2007, and 2006, oil sales volumes were 221 MBbls and 21 MBbls less than oil production volumes, respectively.

(4) Average sales prices for 2004 are net of hedges. The price without hedges for 2004 was $38.85 per barrel of oil and $36.45 per barrel of oil equivalent.

(5) Average costs per Boe have been computed using sales volumes.

(6) EBITDAX represents earnings before interest expense, income taxes, depreciation, depletion, amortization and accretion, property impairments, exploration expense, unrealized derivative gains or losses 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 revolving credit facility requires that we maintain a Total Funded Debt to EBITDAX ratio of no greater than 3.75 to 1 on a rolling four-quarter basis. Our revolving credit facility defines EBITDAX consistently with the definition of EBITDAX utilized and presented by us. At December 31, 2008, our Total Funded Debt to EBITDAX ratio was approximately 0.5 to 1. The following table represents a reconciliation of our net income to EBITDAX for the periods presented:

	Year ended December 31,				
	2008	2007	2006 (in thousands)	2005	2004
Net income	$ 320,950	$ 28,580	$ 253,088	$ 194,307	$ 27,864
Unrealized derivative loss		26,703			
Interest expense	12,188	12,939	11,310	14,220	23,617
Provision (benefit) for income taxes	197,580	268,197	(132)	1,139	
Depreciation, depletion, amortization and accretion	148,902	93,632	65,428	49,802	38,627
Property impairments	28,847	17,879	11,751	6,930	11,747
Exploration expense	40,160	9,163	19,738	5,231	12,633
Equity compensation	9,081	12,792	10,932	13,715	2,010
EBITDAX	$ 757,708	$ 469,885	$ 372,115	$ 285,344	$ 116,498

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

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 report.

Overview

We are engaged in oil and natural gas exploration, exploitation and production activities in the Rocky Mountain, Mid-Continent and Gulf Coast regions of the United States. Crude oil comprised 67% of our 159.3 MMBoe of estimated proved reserves as of December 31, 2008 and 76% of our 12,006 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 91% of our PV-10 and 76% of our 2,192 gross wells as of December 31, 2008. 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, 2008, we added 81,306 MBoe of proved reserves through extensions and discoveries, compared to 2,649 MBoe added through purchases. During this period, our production increased from 9,018 MBoe in 2006 to 12,006 MBoe in 2008. An aspect of our business strategy has been to acquire large undeveloped acreage positions in new or developing resource plays. As of December 31, 2008, we held approximately 2,025,956 gross (1,114,445 net) undeveloped acres, including 479,435 net acres in the Bakken field in Montana and North Dakota and 59,697 net acres in the Arkoma Woodford and Lewis Shale projects. As an early entrant in new or emerging plays, we expect to acquire undeveloped acreage at a lower cost than those of later entrants into a developing play.

In the year ended December 31, 2008, our oil and gas production increased to 12,006 MBoe (32,803 Boe per day), up 13% from the year ended December 31, 2007. The increase in 2008 production primarily resulted from an increase in production from our Red River units, Bakken field and Arkoma Woodford. Oil and natural gas revenues for the year 2008 increased by 55% to $939.9 million due to increases in volumes and commodity prices. Our realized price per Boe increased $19.35 to $77.66 for the year 2008 compared to the year 2007. While we experienced increases in production expense and production tax of a combined total of $51.2 million, or 47%, our increase in combined per unit cost was only 26%, or $2.76 per Boe, due to the increase in sales volumes of 1,702 MBoe, or 16%. Oil sales volumes were 97 MBbls more than oil production for the year ended December 31, 2008 due to temporarily stored barrels being sold during the year and oil sales volumes were 221 MBbls less for the same period in 2007 due to an increase in crude oil inventory for pipeline line fill and stored barrels. Our cash flow from operating activities for the year ended December 31, 2008, was $719.9 million, an increase of $329.3 million from $390.6 million provided by our operating activities during the comparable 2007 period. The increase in operating cash flows was mainly due to increases in sales prices and volumes partially offset by increased production expenses and production taxes. During the year ended December 31, 2008, we invested $988.6 million (inclusive of non-cash accruals of $41.1 million) in our capital program concentrating mainly in the Red River units, the Bakken field and the Arkoma Woodford play.

As a response to significantly lower oil and natural gas prices during the fourth quarter of 2008 and continuing into 2009 and the resulting decrease in cash flows, we have significantly reduced our capital expenditures budget for 2009. We have reduced our rig count from 32 operated rigs in October 2008 to 8 operated rigs in early February 2009. While we have an approved capital expenditures budget for 2009 of $275 million, we expect to manage our capital expenditures for the year to be inline with our cash flows from operations. Continued weakness in commodity prices may result in a decrease in our actual capital expenditures during 2009. Conversely, a significant improvement in product prices could result in an increase in our capital expenditures. See Liquidity and Capital Resources.

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How We Evaluate Our Operations

We use a variety of financial and operational measures to assess our performance. Among these measures are (1) volumes of oil and natural gas produced, (2) oil and natural gas prices realized, (3) per unit operating and administrative costs and (4) EBITDAX. The following table contains financial and operational highlights for each of the three years ended December 31, 2008.

	Year ended December 31,		
	2008	**2007**	**2006**
Average daily production:			
Oil (Bopd)	24,993	23,832	20,494
Natural gas (Mcfd)	46,861	31,599	25,274
Oil equivalents (Boepd)	32,803	29,099	24,706
Average prices:(1)			
Oil ($/Bbl)	$ 88.87	$ 63.55	$ 55.30
Natural gas ($/Mcf)	6.90	5.87	6.08
Oil equivalents ($/Boe)	77.66	58.31	52.09
Production expense ($/Boe)(1)	8.40	7.35	6.99
General and administrative expense ($/Boe)(1)	2.95	3.15	3.45
EBITDAX (in thousands)(2)	757,708	469,885	372,115
Net income (in thousands)(3)	320,950	28,580	253,088
Pro forma net income (in thousands)(4)		184,002	156,833
Diluted net income per share	1.89	0.17	1.59
Pro forma diluted net income per share(4)		1.11	0.96

(1) Oil sales volumes were 97 MBbls more than oil production for the year ended December 31, 2008 due to the sale of temporarily stored barrels. Oil sales volumes were 221 MBbls less than oil production for the year ended December 31, 2007 and 21 MBbls less than oil production for the year ended December 31, 2006 due to temporary storage and pipeline line fill. Average prices and per unit expenses have been calculated using sales volumes and excluding any effect of derivative transactions.

(2) EBITDAX represents earnings before interest expense, income taxes (when applicable), depreciation, depletion, amortization and accretion, property impairments, exploration expense, unrealized derivative gains and losses and non-cash compensation expense. EBITDAX is not a measure of net income or cash flow as determined by GAAP. A reconciliation of net income to EBITDAX is provided in Item 6. Selected Financial Data.

(3) Prior to our initial public offering, we were a subchapter S corporation and income taxes were payable by our shareholders and as a result, there was a minimal provision for income taxes for the periods ended December 31, 2006. See *Notes to Consolidated Financial Statements Note 1. Organization and Summary of Significant Accounting Policies Income taxes*. In connection with our initial public offering, we converted to a subchapter C corporation and recorded a charge to earnings in the second quarter of 2007 of $198.4 million to recognize deferred taxes relating to the temporary differences that existed at May 14, 2007, the date we converted to a subchapter C corporation.

(4) Pro forma adjustments are reflected to provide for income taxes in accordance with SFAS No. 109 as if we had been a subchapter C corporation for all periods presented. A statutory Federal tax rate of 35% and effective state tax rate of 3% (net of Federal income tax effects) were used for the pro forma enacted tax rate for all pro forma periods presented.

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Results of Operation

The following table presents selected financial and operating information for each of the three years ended December 31, 2008:

(in thousands, except price data)	Year Ended December 31, 2008	2007	2006
Oil and natural gas sales	$ 939,906	$ 606,514	$ 468,602
Derivatives	(7,966)	(44,869)	
Total revenues	960,490	582,215	483,652
Operating costs and expenses	431,167	274,248	221,128
Other expense	10,793	11,190	9,568
Net income, before income taxes	518,530	296,777	252,956
Provision (benefit) for income taxes(1)	197,580	268,197	(132)
Net income	$ 320,950	$ 28,580	$ 253,088
Production Volumes:			
Oil (MBbl)	9,147	8,699	7,480
Natural gas (MMcf)	17,151	11,534	9,225
Oil equivalents (MBoe)	12,006	10,621	9,018
Sales Volumes:			
Oil (MBbl)	9,244	8,478	7,459
Natural gas (MMcf)	17,151	11,534	9,225
Oil equivalents (MBoe)	12,103	10,400	8,997
Average Prices:(2)			
Oil ($/Bbl)	$ 88.87	$ 63.55	$ 55.30
Natural gas ($/Mcf)	$ 6.90	$ 5.87	$ 6.08

(1) Prior to the public offering, we were a subchapter S corporation and income taxes were payable by our shareholders and as a result, there was a minimal provision for income taxes for the periods ended December 31, 2006. See *Notes to Consolidated Financial Statements Note 1. Organization and Summary of Significant Accounting Policies Income taxes*. In connection with the public offering, we converted to a subchapter C corporation and recorded a charge to earnings in the second quarter of 2007 of $198.4 million to recognize deferred taxes relating to the temporary differences that existed at May 14, 2007, the date we converted to a subchapter C corporation.

(2) Oil sales volumes were 97 MBbls more than oil production for the year ended December 31, 2008 due to the sale of temporarily stored barrels. Oil sales volumes were 221 MBbls less than oil production for the year ended December 31, 2007 and 21 MBbls less than oil production for the year ended December 31, 2006 due to temporary storage and pipeline line fill. Average prices and per unit expenses have been calculated using sales volumes and excluding any effect of derivative transactions.

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Year ended December 31, 2008 compared to the year ended December 31, 2007

Production

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

	Year Ended December 31, 2008		2007		Volume	Percent
	Volume	**Percent**	**Volume**	**Percent**	**Increase**	**Increase**
Oil (MBbl)	9,147	76%	8,699	82%	448	5%
Natural Gas (MMcf)	17,151	24%	11,534	18%	5,617	49%
Total (MBoe)	12,006	100%	10,621	100%	1,385	13%

	Year Ended December 31, 2008		2007		Volume	Percent
	MBoe	**Percent**	**MBoe**	**Percent**	**Increase**	**Increase**
Rocky Mountain	9,246	77%	8,619	81%	627	7%
Mid-Continent	2,547	21%	1,794	17%	753	42%
Gulf Coast	213	2%	208	2%	5	2%
Total (MBoe)	12,006	100%	10,621	100%	1,385	13%

Oil production volumes increased 5% during the year ended December 31, 2008 in comparison to the year ended December 31, 2007. Production increases in the Rocky Mountain area contributed incremental volumes in excess of 2007 levels of 313 MBbls, including 219 MBbls which came from the Bakken field. The Mid-Continent area contributed incremental volumes of 113 MBbls in excess of 2007 levels. Favorable results from drilling and acquisitions have been the primary contributors to production growth in these areas. Gas volumes increased 5,617 MMcf, or 49%, during the year ended December 31, 2008 compared to 2007. The majority of the increase, 3.8 Bcf, was from the Mid-Continent region due to the results of our exploration efforts in the Arkoma Woodford. The Rocky Mountain region gas production was up 1.9 Bcf for the year ended December 31, 2008 compared to 2007 due to additional gas being sold through the Hiland Partners Badlands plant which became operational in late August 2007. Since that time, we have sold 2.8 Bcf of gas from the Red River units through the new plant.

Revenues

Oil and Natural Gas Sales. Oil and natural gas sales for the year ended December 31, 2008 were $939.9 million, a 55% increase from sales of $606.5 million for 2007. Our sales volumes increased 1,703 MBoe or 16% over the 2007 volumes due to the continuing success of our enhanced oil recovery and drilling programs. Our realized price per Boe increased $19.35 to $77.66 for the year ended December 31, 2008 from $58.31 for the year ended December 31, 2007. During 2008, the differential between NYMEX calendar month average crude oil prices and our realized crude oil prices widened. The differential per barrel for the year ended December 31, 2008 was $9.50 compared to $8.85 for 2007. Factors contributing to the higher differentials in 2008 included Canadian oil imports, increases in production in the Rocky Mountain region, coupled with downstream transportation capacity constraints, refinery downtime in the Rocky Mountain region, and reduced seasonal demand for gasoline.

Derivatives. In July 2007, we entered into fixed-price swap contracts covering 10,000 barrels of oil per day for the period from August 2007 through April 2008. During each month of the contract, we received a fixed-price of $72.90 per barrel and paid to the counterparties the average of the prompt NYMEX crude oil futures contract settlement prices for such month. SFAS No. 133, *Accounting for Derivative Instruments and Hedging Activities* requires recognition of all derivative instruments on the balance sheet as either assets or liabilities measured at fair value. We elected not to designate our derivatives as cash flow hedges under the provisions of SFAS No. 133. As a result, we marked our derivative instruments to fair value in accordance with the provisions

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of SFAS No. 133 and recognized the realized and unrealized change in fair value as a gain (loss) on derivative instruments in the statements of income. These contracts expired in April 2008 and during the year ended December 31, 2008, we had recognized losses on derivatives of $8.0 million. We did not have any open derivative positions at December 31, 2008.

Oil and Natural Gas Service Operations. Our oil and natural gas service operations consist primarily of sales of high-pressure air and the treatment and sale of lower quality crude oil, or reclaimed oil. We sold high-pressure air from our Red River units to a third party and recorded revenues of $3.0 million for the year ended December 31, 2008 and revenues of $3.1 million for the year ended December 31, 2007. Prices for reclaimed oil sold from our central treating unit were higher for the year ended December 31, 2008 than the comparable 2007 period. The price increased $27.45 per barrel which increased reclaimed oil income by $6.5 million contributing to an overall increase in oil and gas service operations revenue of $8.0 million for the year ended December 31, 2008. Associated oil and natural gas service operations expenses increased $5.5 million to $18.2 million during the year ended December 31, 2008 from $12.7 million during the year ended December 31, 2007 due mainly to an increase in the costs of purchasing and treating oil for resale compared to the same period in 2007.

Operating Costs and Expenses

Production Expense and Tax. Production expense increased $25.1 million, or 33%, during the year ended December 31, 2008 to $101.6 million from $76.5 million during the year ended December 31, 2007. The increase in production expense is partially attributable to our increase in sales volumes of 16% which is a direct result of new wells being drilled and escalating field service costs. During the year ended December 31, 2008, we participated in the completion of 359 gross (152.5 net) wells. Production expense per Boe increased to $8.40 for the year ended December 31, 2008 from $7.35 per Boe for the year ended December 31, 2007.

Production taxes increased $26.0 million, or 80%, during the year ended December 31, 2008 compared to the year ended December 31, 2007 as a result of higher revenues resulting from increased sales prices and volumes and the expiration of various tax incentives. The majority of the production tax increase was in the Mid-Continent and Rocky Mountain regions due to an increase of 1,697 MBoe sold in the year ended December 31, 2008 compared to the year ended December 31, 2007. Production tax as a percentage of oil and natural gas sales was 6.2% for the year ended December 31, 2008 compared to 5.4% for the year ended December 31, 2007. 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 Montana, North Dakota and Oklahoma new horizontal wells qualify for a tax incentive and are taxed at a lower rate during their initial months of production. After the incentive period expires, the tax rate increases to the statutory rates. Our overall rate is expected to increase as production tax incentives we currently receive for horizontal wells reach the end of their incentive period.

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

($/Boe)	Year Ended December 31, 2008	Year Ended December 31, 2007	Percent Increase
Production expense	$ 8.40	$ 7.35	14%
Production tax	4.84	3.13	55%
Production expense and tax	$ 13.24	$ 10.48	26%

Exploration Expense. Exploration expense consists primarily of dry hole costs and exploratory geological and geophysical costs that are expensed as incurred. Exploration expense increased $31.0 million in the year ended December 31, 2008 to $40.2 million due primarily to an increase in dry hole expense of $16.5 million to $20.0 million and an increase in seismic expense of $14.0 million to $16.9 million. The majority of the dry hole costs were in the Rocky Mountain region for the years ended December 31, 2008 and 2007.

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Depreciation, Depletion, Amortization and Accretion (DD&A). Total DD&A increased $55.3 million in 2008 primarily due to an increase in oil and gas DD&A of $54.4 million as a result of increased production and additional properties being added through our drilling program and acquisitions. Additionally, DD&A increased as a result of the decrease in commodity prices used to calculate year end reserves volumes. Lower prices have the effect of decreasing the economic life of oil and gas properties, which lowers future reserve volumes and increases DD&A. The following table shows the components of our DD&A rate.

	Year Ended December 31,	
($/Boe)	**2008**	**2007**
Oil and gas	$ 11.91	$ 8.63
Other equipment	0.22	0.19
Asset retirement obligation accretion	0.17	0.18
Depreciation, depletion, amortization and accretion	$ 12.30	$ 9.00

Property Impairments. Property impairments, both non-producing and developed, increased in the year ended December 31, 2008 by $10.9 million to $28.8 million compared to $17.9 million during the year ended December 31, 2007. Impairment of non-producing properties increased $3.3 million during the year ended December 31, 2008 to $16.5 million compared to $13.2 million for 2007 reflecting higher amortization of lease costs in our existing fields resulting from further defining likely drilling locations and amortization of new fields. Non-producing properties consist of undeveloped leasehold costs and costs associated with the purchase of certain proved undeveloped reserves. Non-producing properties are amortized on a composite method based on our estimated experience of successful drilling and the average holding period.

Impairment provisions for developed oil and gas properties were approximately $12.3 million for the year ended December 31, 2008 compared to approximately $4.7 million for the year ended December 31, 2007, an increase of $7.6 million, or 161%. We evaluate our developed oil and gas properties for impairment by comparing their cost basis to the estimated future cash flows on a field basis. If the cost basis is in excess of estimated future cash flows, then we impair it based on an estimate of fair market value based on discounted cash flows. Impairments in 2008 reflect uneconomic drilling results in certain small fields primarily in our Mid-Continent region and our Rockies Other area which resulted in impairments of $8.8 million in 2008. The significant decrease in oil and gas prices at December 31, 2008 resulted in 2008 impairments of $3.5 million. Impairments in 2007 were primarily related to uneconomic wells in our Gulf region and certain small fields primarily in our Mid-Continent region.

General and Administrative Expense. General and administrative expense increased $2.9 million to $35.7 million during the year ended December 31, 2008 from $32.8 million during the comparable period of 2007. General and administrative expense includes non-cash charges for stock-based compensation of $9.1 million and $12.8 million for the years ended December 31, 2008 and 2007, respectively. Stock compensation expense was higher in 2007 due to an increase in the value of our stock as we approached our initial public offering. Until our initial public offering in May 2007, the outstanding options and restricted stock were accounted for as liability awards and their value fluctuated with the value of the underlying stock. General and administrative expense excluding equity compensation increased $7.2 million for the twelve months ended December 31, 2008 compared to the twelve months ended December 31, 2007. The increase was primarily related to a $6.6 million increase in personnel costs due to additional employees and higher wages and increased benefits. On a volumetric basis, general and administrative expense was $2.95 per Boe for the year ended December 31, 2008 compared to $3.15 per Boe for the year ended December 31, 2007 due to higher sales volumes.

Interest Expense. Interest expense decreased 6%, or $0.8 million, for the year ended December 31, 2008 compared to the year ended December 31, 2007, due to lower interest rates during 2008 partially offset by higher debt balances. Our average debt balance increased to $248.7 million for the year ended December 31, 2008 compared to $182.2 million for the year ended December 31, 2007, but the weighted average interest rate on our

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revolving credit facility was 1.93% lower at 4.54% for the year ended December 31, 2008 compared to 6.47% for the same period in 2007. At December 31, 2008 our outstanding debt balance was $376.4 million with a weighted average interest rate of 4.11%.

Income Taxes. Income taxes for the year ended December 31, 2008 were $197.6 million compared to $268.2 million for the year ended December 31, 2007. The 2007 taxes included $198.4 million recorded to recognize deferred taxes upon the conversion from a subchapter S corporation to a subchapter C corporation on May 14, 2007 for temporary differences that existed at that date primarily as a result of deducting intangible drilling costs for tax purposes. We provide taxes at a combined federal and state tax rate of approximately 38% after taking into account permanent taxable differences. See Notes to Consolidated Financial Statements Note 7 for more information.

Year ended December 31, 2007 compared to the year ended December 31, 2006

Production

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

	Year Ended December 31, 2007		2006		Volume	Percent
	Volume	Percent	Volume	Percent	increase	increase
Oil (MBbl)[1]	8,699	82%	7,480	83%	1,219	16%
Natural Gas (MMcf)	11,534	18%	9,225	17%	2,309	25%
Total (MBoe)	10,621	100%	9,018	100%	1,603	18%

	Year Ended December 31, 2007		2006		Volume increase	Percent increase
	MBoe	Percent	MBoe	Percent	(decrease)	(decrease)
Rocky Mountain[1]	8,619	81%	7,159	79%	1,460	20%
Mid-Continent	1,794	17%	1,497	17%	297	20%
Gulf Coast	208	2%	362	4%	(154)	(43)%
Total (MBoe)	10,621	100%	9,018	100%	1,603	18%

(1) Oil sales volumes are 221 MBbls and 21 MBbls less than oil production volumes for the years ended 2007 and 2006, respectively, due to temporary storage and pipeline linefill.

Oil production volumes increased 16% during the year ended December 31, 2007 in comparison to the year ended December 31, 2006. Production increases in the Red River units contributed incremental volumes in excess of 2006 levels of 849 MBbls, and the Bakken field contributed 426 MBbls of incremental production. Initial production commenced in the Bakken field in August 2003 and has increased thereafter, as we have continued exploration and development activities within the Montana and North Dakota portions of the field. Favorable results from our enhanced recovery program and increased density drilling have been the primary contributors to production growth in the Red River units. Gas volumes increased 2,309 MMcf, or 25%, during the year ended December 31, 2007 compared to 2006. The majority of the increase, 1,833 MMcf, was from the Mid-Continent region due to the results of our exploration efforts in the Arkoma Woodford. The Rocky Mountain gas production was up 1,227 MMcf for the year ended December 31, 2007 compared to 2006. The new Hiland Partners Badlands Plant became operational in late August 2007. Through December 31, 2007, we sold 672 MMcf of gas from the Red River units through the new plant. We have invested a minimal amount of capital in our Gulf Coast region resulting in a decline in production in this area of 751 MMcf for the year ended December 31, 2007 compared to 2006.

Revenues

Oil and Natural Gas Sales. Oil and natural gas sales for the year ended December 31, 2007 were $606.5 million, a 29% increase from sales of $468.6 million for 2006. Our sales volumes increased 1,403 MBoe, or 16%, over the 2006 volumes due to the continuing success of our enhanced oil recovery and drilling programs. Our realized price per Boe increased $6.22 to $58.32 for the year ended December 31, 2007 from $52.09 for the year ended December 31, 2006. During 2007, the differential between NYMEX calendar month average crude oil prices and our realized crude oil prices narrowed. The differential per barrel for the year ended December 31, 2007 was $8.85 compared to $11.04 for 2006. Factors contributing to the higher differentials in 2006 included Canadian oil imports, increases in production in the Rocky Mountain region, coupled with downstream transportation capacity constraints, refinery downtime in the Rocky Mountain region, and reduced seasonal demand for gasoline. Crude oil differentials were better during 2007 due to additional transportation capacity and efforts by us to move crude oil to more favorable markets.

During the fourth quarter of 2007, we elected not to sell some of our Rocky Mountain area crude oil as price differentials were unacceptable to us and we expected the differentials to improve in early 2008. This resulted in an increase in our crude oil inventory of 125,000 barrels. The price we were offered was adversely affected by seasonal demand. In the fourth quarter of 2007, we shipped some of our Rocky Mountain area crude by railcar to help alleviate this situation. We were able to sell the majority of this oil at improved differentials during January and February 2008.

Derivatives. In July 2007, we entered into fixed-price swap contracts covering 10,000 barrels of oil per day for the period from August 2007 through April 2008. During each month of the contract, we will receive a fixed-price of $72.90 per barrel and will pay to the counterparties the average of the prompt NYMEX crude oil futures contract settlement prices for such month. SFAS No. 133, Accounting for Derivative Instruments and Hedging Activities requires recognition of all derivative instruments on the balance sheet as either assets or liabilities measured at fair value. We elected not to designate our derivatives as cash flow hedges under the provisions of SFAS No. 133. As a result, we mark our derivative instruments to fair value in accordance with the provisions of SFAS No. 133 and recognize the realized and unrealized change in fair value as a gain (loss) on derivative instruments in the statements of income. During the year ended December 31, 2007, we had realized losses on derivatives of $18.2 million and unrealized losses on derivatives of $26.7 million.

Oil and Natural Gas Service Operations. Our oil and natural gas service operations consist primarily of sales of high-pressure air and the treatment and sale of lower quality crude oil, or reclaimed oil. We sold high-pressure air from our Red River units to a third party and recorded revenues of $3.1 million for the years ended December 31, 2007 and 2006. Prices for reclaimed oil sold from our central treating unit were higher for the year ended December 31, 2007 than the comparable 2006 period, and the number of barrels sold increased approximately 68,000 barrels which increased reclaimed oil income by $5.5 million contributing to an overall increase in oil and gas service operations revenue of $5.5 million for the year ended December 31, 2007. Associated oil and natural gas service operations expenses increased $4.5 million to $12.7 million during the year ended December 31, 2007 from $8.2 million during the year ended December 31, 2006 due mainly to an increase in additional barrels treated in 2007 and to an increase of $5.71 per barrel in the costs of purchasing and treating oil for resale compared to the same period in 2006.

Operating Costs and Expenses

Production Expense and Tax. Production expense increased $13.6 million, or 22%, during the year ended December 31, 2007 to $76.5 million from $62.9 million during the year ended December 31, 2006. The increase in production expense is commensurate with our increase in production of 18% which is a direct result of new wells being drilled. Additionally, we have experienced a slight increase in service and energy costs. During the year ended December 31, 2007, we participated in the completion of 262 gross (112.1 net) wells. Production expense per Boe increased to $7.35 per Boe for the year ended December 31, 2007 from $6.99 per Boe for the year ended December 31, 2006.

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Production taxes increased $10.2 million, or 46% during the year ended December 31, 2007 compared to the year ended December 31, 2006 primarily as a result of higher revenues resulting from increased sales volumes and prices. The majority of the production tax increase was in the Rocky Mountain region due to an increase of 1,261 MBoe sold in the year ended December 31, 2007 compared to the year ended December 31, 2006. Production tax as a percentage of oil and natural gas sales was 5.4% for the year ended December 31, 2007 compared to 4.8% for the year ended December 31, 2006. 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 Montana, new horizontal wells qualify for a tax incentive and are taxed at 0.76% during the first 18 months of production. After the 18 month incentive period expires, the tax rate increases to 9.26%. During the year ended December 31, 2007, 32 wells had reached the end of the 18 month incentive period and the tax rate increased from 0.76% to 9.26%. Our overall rate is expected to increase as production tax incentives received for horizontal wells in Montana reach the end of the 18 month incentive period. We are also receiving a 6% tax incentive on horizontal wells drilled in the Arkoma Woodford play in Oklahoma that continues for up to four years or until the revenue from such well exceeds the cost to drill and complete. In North Dakota, we are receiving a 4.5% tax credit on horizontal Bakken wells spud after July 1, 2007 and completed before June 30, 2008. The incentive expires on the earliest to occur of 75,000 barrels of production or eighteen months.

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

($/Boe)	Year Ended December 31, 2007	Year Ended December 31, 2006	Percent Increase
Production expense	$ 7.35	$ 6.99	5%
Production tax	3.13	2.48	26%
Production expense and tax	$ 10.48	$ 9.47	11%

Exploration Expense. Exploration expense consists primarily of dry hole costs and exploratory geological and geophysical costs that are expensed as incurred. Exploration expenses decreased $10.6 million in the year ended December 31, 2007 to $9.2 million due primarily to a decrease in dry hole expense of $9.8 million and a decrease in seismic expense of $0.9 million. The majority of the dry hole costs were in the Mid-Continent region in the 2006 period and in the Mid-Continent and Rocky Mountain regions in the same period in 2007. Dry hole costs were down in 2007 even though exploratory capital expenditures increased by approximately 144% as a result of more successful exploration activities.

Depreciation, Depletion, Amortization and Accretion (DD&A.). Total DD&A increased $28.2 million in 2007 primarily due to an increase in oil and gas DD&A of $27.9 million as a result of increased production and additional properties being added through our drilling program. The DD&A rate for the year ended December 31, 2007 was $9.00 per Boe, including $8.63 per Boe on oil and gas properties and $0.37 per Boe for other equipment and asset retirement obligation accretion, compared to $7.27 per Boe, including $6.91 per Boe for oil and gas properties and $0.36 per Boe for other equipment and asset retirement obligation accretion, for the same period in 2006. The increase in the oil and gas DD&A rate reflects the additional costs incurred to develop proved undeveloped reserves and the higher costs of drilling and completing wells.

Property Impairments. Property impairments increased in the year ended December 31, 2007 by $6.1 million to $17.9 million compared to $11.8 million during the year ended December 31, 2006. Impairment of non-producing properties increased $7.7 million during the year ended December 31, 2007 to $13.2 million compared to $5.5 million for 2006 reflecting higher amortization of lease costs in our existing fields resulting from further defining likely drilling locations and amortization of new fields. Non-producing properties consist of undeveloped leasehold costs and costs associated with the purchase of certain proved undeveloped reserves. Individually significant non-producing properties are periodically assessed for impairment of value and a loss is recognized at the time of impairment by providing an impairment allowance. Other non-producing properties are amortized on a composite method based on our estimated experience of successful drilling and the average holding period.

Impairment provisions for developed oil and gas properties were approximately $4.7 million for the year ended December 31, 2007 compared to approximately $6.3 million for the year ended December 31, 2006.

General and Administrative Expense. General and administrative expense increased $1.7 million to $32.8 million during the year ended December 31, 2007 from $31.1 million during the comparable period of 2006. General and administrative expense includes non-cash charges for stock-based compensation of $12.8 million and $10.9 million for the years ended December 31, 2007 and 2006, respectively. The increase was due to new grants under the Continental Resources, Inc. 2005 Long-Term Incentive Plan (2005 Plan) during the year ended December 31, 2007. On a volumetric basis, general and administrative expense was $3.15 per Boe for the year ended December 31, 2007 compared to $3.45 per Boe for the year ended December 31, 2006. We have granted stock options and restricted stock to our employees and directors. While we were a private company, the terms of the grants required us to purchase vested options and restricted stock at each employee s request. The obligation to purchase the options was eliminated when we became a reporting company under Section 12 of the Securities Exchange Act of 1934, as amended, on May 14, 2007.

Interest Expense. Interest expense increased 14%, or $1.6 million, for the year ended December 31, 2007 compared to the year ended December 31, 2006, due to a higher average outstanding debt balance on our revolving credit facility. Our average debt balance was $182.2 million for the year ended December 31, 2007 compared to $156.6 million for the year ended December 31, 2006. The weighted average interest rate on our revolving credit facility was slightly higher at 6.47% for the year ended December 31, 2007 compared to 6.36% for the same period in 2006. At December 31, 2007 our outstanding debt balance was $165.0 million.

Income Taxes. Income taxes for the year ended December 31, 2007 were $268.2 million and included $198.4 million recorded to recognize deferred taxes upon the conversion from a subchapter S corporation to a subchapter C corporation on May 14, 2007 for temporary differences that existed at that date primarily as a result of deducting intangible drilling costs for tax purposes. We provide taxes at a combined federal and state tax rate of approximately 38% after taking into account permanent taxable differences. See Notes to Consolidated Financial Statements Note 8 for more information.

Liquidity and Capital Resources

Our primary sources of liquidity have been cash flows generated from operating activities and financing provided by our revolving credit facility. As we exited the fourth quarter of 2008, oil and natural gas prices had declined significantly from their recent record levels which reduced our operational cash flows. In response, we began reducing capital expenditures during the last quarter of 2008 and have prepared our capital expenditure budget for 2009 assuming lower commodity prices. However, realigning capital expenditures to reflect lower cash flows is not an instantaneous process; accordingly our debt has increased and will continue to increase as operating activities and expenses are matched with the reduced level of cash flow. Additionally, as in the past, we will consider selling non-strategic assets in order for us to focus on our core projects if and when appropriate.

The recent problems in the credit markets, steep stock market declines, financial institution failures and government bail-outs are evidence of a weakening global economy. If the unsettled conditions, including sustained declines in commodity prices, continue long term it may impact our ability to develop all of our projects. Our current revolving credit facility is backed by a syndicate of 14 banks and we believe that all of the syndicate banks have the capability to fund up to our current commitment. If one or more banks should not be able to do so, we may not have the full availability of $672.5 million commitment.

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We believe that funds from operating cash flows and the revolving credit facility should be sufficient to meet our cash requirements inclusive of, but not limited to, normal operating needs, debt service obligations, planned capital expenditures, and commitments and contingencies for the next 12 months.

We currently anticipate that we will be able to generate or obtain funds sufficient to meet our long-term cash requirements. 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 or the sale of assets. Please see Risk Factors. Lower oil and natural gas prices will reduce our cash flows and borrowing ability. For example, although our average realized price received for oil and natural gas was $77.66 per Boe for the year ended December 31, 2008, it was bolstered by record oil prices for the first half of the year. In the fourth quarter of 2008, our average realized price received for oil and natural gas declined to $38.80 per Boe. Furthermore, the issuance of additional debt may 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.

In the future, we may not be able to access adequate funding under our bank credit facilities as a result of (i) a decrease in our borrowing base due to the outcome of a subsequent borrowing base redetermination, or (ii) an unwillingness or inability on the part of our lending counterparties to meet their funding obligations. The recent declines in commodity prices, or a continuing decline in those prices, could result in a determination to lower the borrowing base in the future and, in such case, we could be required to repay any indebtedness in excess of the borrowing base. The turmoil in the financial markets has adversely impacted the stability and solvency of a number of large global financial institutions.

The current credit crisis makes it difficult to obtain funding in the public and private capital markets. In particular, the cost of raising money in the debt and equity capital markets has increased substantially while the availability of funds from those markets generally has diminished significantly. Also, as a result of concerns about the general stability of financial markets and the solvency of specific counterparties, the cost of obtaining money from the credit markets has increased as many lenders and institutional investors have increased interest rates, imposed tighter lending standards, refused to refinance existing debt at maturity at all or on terms similar to existing debt or at all, and reduced and, in some cases, ceased to provide any new funding.

The credit crisis also has impacted the level of activity in the oil and natural gas property sales market. The lack of available credit and access to capital has limited and will likely continue to limit the parties interested in any proposed asset transactions and will likely reduce the values we could realize in those transactions.

Due to these factors, we cannot be certain that funding, if needed, will be available to the extent required and on acceptable terms. If we are unable to access funding when needed on acceptable terms, we may not be able to fully implement our business plans, complete new property acquisitions to replace our reserves, take advantage of business opportunities, respond to competitive pressures, or refinance our debt obligations as they come due, any of which could have a material adverse effect on our operations and financial results.

Cash Flow from Operating Activities

Our net cash provided by operating activities was $719.9 million, $390.6 million and $417.0 million for the years ended December 31, 2008, 2007 and 2006, respectively. The increase in operating cash flows for the year ended December 31, 2008 was mainly due to increases in revenues reflecting increased production volumes and product prices partially offset by higher operating costs.

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Cash Flow from Investing Activities

During the years ended December 31, 2008, 2007 and 2006 we had cash flows used in investing activities (excluding asset sales) of $930.8 million, $486.4 million and $326.6 million, respectively, in our capital program, inclusive of dry hole and seismic costs. The increase in our capital program for the year ended December 31, 2008 was mainly due to increased drilling in our Rocky Mountain region and in our Arkoma Woodford shale play.

Cash Flow from Financing Activities

Net cash provided by financing activities of $204.2 million for the year ended December 31, 2008, was mainly the result of amounts borrowed under our revolving credit facility to fund capital expenditures, including acquisitions. Net cash provided by financing activities of $94.6 million for the year ended December 31, 2007 was mainly the results of proceeds of our initial public offering net of amounts used to pay cash dividends. Net cash used in financing activities during 2006 of $91.5 million was used mainly for the payment of cash dividends.

Credit Facility

We had $376.4 million and $165.0 million outstanding under our revolving credit facility at December 31, 2008 and 2007, respectively. As of February 23, 2009, the amount outstanding under our credit facility has increased by $98.0 million to $474.4 million. The increase was largely due to borrowings to cover capital expenditures incurred in the fourth quarter of 2008 that could not be funded from cash flow from operations due to the continued deterioration in oil and natural gas prices in the second half of 2008 and into 2009.

The revolving credit facility matures on April 12, 2011, and borrowings under our revolving 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 175 to 250 basis points, depending on the percentage of our borrowing base utilized or (b) the lead bank s reference rate. At December 31, 2008 and 2007, we had cash and cash equivalents of $5.2 million and $8.8 million, respectively, and available borrowing capacity on our revolving credit facility of $176.1 million and $135.0 million, respectively. At February 23, 2009, we had available borrowing capacity on our revolving credit facility of $198.1 million.

The revolving credit facility was amended in December 2008 to change the borrowing base to $850.0 million, subject to semi-annual redetermination, increase the applicable London Interbank Offered Rate margins by 75 basis points to a range of 175 to 250 basis points and increase the commitment level to $552.5 million. Subsequently, in February 2009, the commitment level was increased to $672.5 million. The note amount remains at $750.0 million. Borrowings under the revolving credit facility are secured by liens on substantially all of our oil and gas properties and associated assets. Our next semi-annual redetermination will occur in April 2009. The terms of the revolving credit facility commitment level can be increased up to the lesser of the borrowing base or note amount subject to bank agreement.

The revolving credit facility contains restrictive covenants that may limit our ability to, among other things, incur additional indebtedness, sell assets, make loans to others, make investments, enter into mergers, change material contracts, incur liens and engage in certain other transactions without the prior consent of the lenders. The facility also requires us to maintain certain ratios as defined and further described in our revolving credit facility: a Current Ratio of not less than 1.0 to 1.0 (adjusted for available borrowing capacity), a Total Funded Debt to EBITDAX, as defined therein, of no greater than 3.75 to 1.0. As of December 31, 2008, we were in compliance with all covenants.

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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. Acquisition expenditures are not budgeted.

We invested approximately $988.6 million (inclusive of non-cash accruals of $41.1 million) for capital and exploration expenditures in 2008 as follows (in millions):

	Amount
Exploration and development drilling	$ 634.3
Acquisition of producing properties	74.7
Capital facilities, workovers and re-completions	42.1
Land costs	206.2
Seismic	16.9
Vehicles, computers and other equipment	14.4
Total	$ 988.6

Expenditures for exploration and development of oil and natural gas properties are the primary use of our capital resources. In November 2008, our Board of Directors approved budgeted capital expenditures of approximately $609.0 million. However, as a response to significantly lower oil and natural gas prices during the fourth quarter of 2008 and continuing into 2009 and the resulting decrease in expected cash flows, we have significantly reduced our capital expenditures budgeted for 2009. In addition, we have reduced our rig count from 32 operated rigs in October 2008 to 7 operated rigs on February 23, 2009. We expect to manage our capital expenditures for the year to be inline with our cash flows from operations. Continued weakness in commodity prices may result in a further decrease in our actual capital expenditures during 2009. Conversely, a significant improvement in commodity prices could result in an increase in our actual capital expenditures during 2009. In February 2009, our Board of Directors approved a decrease in our budgeted capital expenditures to $275.0 million as follows (in millions):

	Amount
Exploration and development drilling	$ 164.6
Capital facilities, workovers and re-completions	46.4
Land costs	54.0
Seismic	4.0
Vehicles, computers and other equipment	6.0
Total	$ 275.0

Our budgeted capital expenditures are expected to decrease approximately 72% from the $988.6 million invested during 2008. We plan to invest approximately $71.4 million in development drilling. In the Red River units, we plan to invest approximately $46.0 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 $93.2 million for exploratory drilling with approximately $51.0 million and $18.0 million allocated to drilling exploratory wells in the North Dakota Bakken field and the Arkoma Woodford project, respectively.

Although we cannot provide any assurance, assuming successful implementation of our strategy, including the future development of our proved reserves and realization of our cash flows as anticipated, we believe that our remaining cash balance, cash flows from operations and borrowings available under our revolving credit facility will be sufficient to satisfy our 2009 capital budget. The actual amount and timing of our capital expenditures may differ materially from our estimates as a result of, among other things, available cash flow, actual drilling results, the availability of drilling rigs and other services and equipment, and regulatory, technological and competitive developments.

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Shareholder Distribution

On January 10, 2007, we declared a cash dividend of approximately $18.8 million to our shareholders and, subject to forfeiture, to holders of unvested restricted stock. On January 31, 2007, we paid $18.7 million of the dividend declared, of which $16.9 million was paid to our principal shareholder. On March 6, 2007, we declared a cash dividend of approximately $33.3 million to our shareholders of record and, subject to forfeiture, to holders of unvested restricted stock. On April 12, 2007, we paid $33.1 million of the dividend declared, of which $30.0 million was paid to our principal shareholder. We converted from a subchapter S corporation to a subchapter C corporation on May 14, 2007 when we became a publicly traded company, and we do not anticipate paying any additional cash dividends on our common stock in the foreseeable future.

Obligations and Commitments

We have the following contractual obligations and commitments as of December 31, 2008:

	Payments due by period				
	Total	Less than 1 year	1 - 3 years	3 - 5 years	More than 5 years
	(in thousands)				
Revolving credit facility	$ 376,400	$	$ 376,400	$	$
Interest expense(1)	35,221	15,470	19,751		
Operating leases	1,758	1,489	265	4	
Drilling rig commitments(2)	35,045	20,516	14,529		
Asset retirement obligations(3)	44,630	4,747	7,573	2,818	29,492
Total contractual cash obligations	$ 493,054	$ 42,222	$ 418,518	$ 2,822	$ 29,492

(1) Interest expense assumes that the year-end interest rate of 4.11% continues for the life of the revolving credit facility.

(2) See Notes to Consolidated Financial Statements Note 10. Commitments and Contingencies Drilling Commitments for a description of drilling contract commitments.

(3) Amounts represent expected asset retirements by period.

Critical Accounting Policies and Practices

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

In management s opinion, the more significant reporting areas impacted by management s judgments and estimates are oil and natural gas reserve estimation , revenue recognition, the choice of accounting method for oil and natural gas activities, asset retirement obligations, impairment of assets and income taxes. 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.

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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. Oil and natural gas reserve engineering is a subjective process of estimating underground accumulations of oil and natural gas that cannot be precisely measured. The accuracy of any reserve estimate is a function of the quality of available data and of engineering and geological interpretation and judgment. 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. Accordingly, reserve estimates are often different from the quantities of oil and gas that are ultimately recovered. 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.

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 a field 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 a field 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.

Unproved oil and natural gas properties, the majority of the costs of which relates to the acquisition of leasehold interests, are assessed for impairment on a property-by-property basis for individually significant balances and on an aggregate basis for individually insignificant balances. If the assessment indicates an impairment, a loss is recognized by providing a valuation allowance at the level consistent with the level at which impairment was assessed. The impairment assessment is affected by economic factors such as the results of exploration activities, commodity price outlooks, remaining lease terms, and potential shifts in business strategy employed by management. In the case of individually insignificant balances, the amount of the impairment loss recognized is determined by amortizing the portion of the unproved properties costs which we feel will not be transferred to proved properties over the life of the lease.

Asset Retirement Obligations

We are required to recognize an estimated liability for future costs associated with the abandonment of our oil and gas properties. We base our estimate of the liability on our historical experience in abandoning oil and gas wells projected into the future based on our current understanding of federal and state regulatory requirements. Our present value calculations require us to estimate the economic lives of our properties, assume what future inflation rates apply to external estimates, and determine what credit adjusted risk-free rate to use. The impact to the consolidated statement of income from these estimates is reflected in our depreciation, depletion, and amortization calculations and occurs over the remaining life of our oil and gas properties.

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.

Income Taxes

We make certain estimates and judgments in determining our income tax expense for financial reporting purposes. These estimates and judgments occur in the calculation of certain tax assets and liabilities that arise from differences in the timing and recognition of revenue and expense for tax and financial reporting purposes. Our federal and state income tax returns are generally not prepared or filed before the consolidated financial statements are prepared; therefore, we estimate the tax basis of our assets and liabilities at the end of each period as well as the effects of tax rate changes, tax credits and net operating loss carryforwards. Adjustments related to these estimates are recorded in our tax provision in the period in which we file our income tax returns. Further, we must assess the likelihood that we will be able to recover or utilize our deferred tax assets. If recovery is not likely, we must record a valuation allowance against such deferred tax assets for the amount we would not expect to recover, which would result in an increase to our income tax expense. As of December 31, 2008, we believe that all of our deferred tax assets recorded on our Consolidated Balance Sheet will ultimately be recovered. We consider future taxable income in making such assessments. Numerous judgments and assumptions are inherent in the determination of future taxable income, including factors such as future operating conditions (particularly as related to prevailing oil and natural gas prices). If our estimates and judgments change regarding our ability to utilize our deferred tax assets, our tax provision would increase in the period it is determined that recovery is not probable.

Our effective tax rate is subject to variability from period to period as a result of factors other than changes in federal and state tax rates and/or changes in tax laws which can affect tax paying companies. Our effective tax rate is affected by changes in the allocation of property, payroll, and revenues between states in which we own property as rates vary from state to state. As the mix of property, payroll, and revenues varies by state, our estimated tax rate changes. Due to the size of our gross deferred tax balances, a small change in our estimated future tax rate can have a material effect on current period earnings.

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Off-Balance Sheet Arrangements

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

Recent Accounting Pronouncements

In December 2007, the FASB issued SFAS No. 141 (revised 2007), Business Combinations (SFAS 141(R)) and SFAS No. 160, Noncontrolling Interests in Consolidated Financial Statements, an amendment of ARB No. 51 (SFAS 160). SFAS 141(R) will change how business acquisitions are accounted for and will impact financial statements both on the acquisition date and in subsequent periods. SFAS 160 will change the accounting and reporting for minority interests, which will be re-characterized as noncontrolling interests and classified as a component of equity. SFAS 141(R) and SFAS 160 are effective for fiscal years beginning on or after December 15, 2008. SFAS 141(R) will be applied prospectively. SFAS 160 requires retroactive adoption of the presentation and disclosure requirements for existing minority interests. All other requirements of SFAS 160 will be applied prospectively. Early adoption is prohibited for both standards. The adoption of SFAS 141(R) and SFAS 160 is not expected to have a material impact on the Company s consolidated financial position or results of operations.

In February 2008, the FASB issued FASB Staff Position FAS 157-2, *Effective Date of FASB Statement No. 157,* which provides a one year delay of the effective date of FAS 157 to January 1, 2009 for non-financial assets and non-financial liabilities, except those that are recognized or disclosed at fair value in the financial statements on a recurring basis (at least annually). The impact of adoption related to the non-financial assets and liabilities will depend on our assets and liabilities at the time they are required to be measured at fair value.

In March 2008, the FASB issued SFAS No. 161, *Disclosures about Derivative Instruments and Hedging Activities an amendment of FASB Statement No. 133,* which amends and expands the disclosure requirements of FAS 133 to require qualitative disclosure about objectives and strategies for using derivatives, quantitative disclosures about fair value amounts of gains and losses on derivative instruments, and disclosures about credit-risk-related contingent features in derivative agreements. This statement will be effective beginning in fiscal 2009. The adoption of this statement will change the disclosures related to our derivative instruments, if any.

In May 2008, the FASB issued SFAS No. 162, *The Hierarchy of Generally Accepted Accounting Principles* (SFAS 162), which identifies the sources of accounting principles and the framework for selecting the principles to be used in preparation of financial statements of nongovernmental entities that are presented in conformity with generally accepted accounting principles in the United States of America. SFAS 162 was adopted by the Company effective November 15, 2008. SFAS 162 did not have a material impact on our consolidated financial position or results of operations.

On December 29, 2008, the Securities and Exchange Commission announced final approval of new requirements, effective for annual reports on Form 10-K for fiscal years ending on or after December 31, 2009, to provide investors with a more meaningful and comprehensive understanding of oil and natural gas reserves. The new disclosure requirements include:

- Consideration of new technologies in evaluating oil and natural gas reserves,
- Disclosure of probable and possible oil and natural gas reserves,
- Use of an average price based on the prior twelve month period rather than year-end prices, and
- Revisions of the oil and natural gas disclosure requirements for operations.

We have not yet evaluated the effects of the above on our financial statements and disclosures.

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Inflation

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

Item 7A. 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 which may include 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 joint interest receivables ($156.6 million at December 31, 2008) and the sale of our oil and natural gas production, which we market to energy marketing companies, refineries and affiliates ($72.4 million in receivables at December 31, 2008). See *Notes to Consolidated Financial Statements. Note 1. Organization and Summary of Significant Accounting Policies.* Joint interest receivables arise from billing entities who own partial interest in the wells we operate. These entities participate in our wells primarily based on their ownership in leases on which we wish to drill. We can do very little to choose who participates in our wells. In order to minimize our exposure to credit risk we request prepayment of drilling costs where it is allowed by contract or state law. For such prepayments, a liability is recorded and subsequently reduced as the associated work is performed. In this manner, we reduce credit risk. We also have the right to place a lien on our co-owners production proceeds in order to secure payment. Historically, our credit losses on joint interest receivables have been immaterial.

We monitor our exposure to counterparties on oil and natural gas sales primarily by reviewing credit ratings, financial statements and payment history. We extend credit terms based on our evaluation of each counterparty s credit worthiness. We have not generally required our counterparties to provide collateral to support oil and natural gas receivables owed to us.

Commodity Price Risk. Our primary market risk exposure is in the pricing applicable to our natural gas and oil production. Realized pricing is primarily driven by the prevailing worldwide price for crude oil and spot market prices applicable to our U.S. natural gas production. Pricing for natural gas and oil production has been volatile and unpredictable for several years, and we expect this volatility to continue in the future. The prices we receive for production depend on many factors outside of our control including volatility in the differences between product prices at sales points and the applicable index price. Based on our average daily production for the year ended December 31, 2008, our annual revenue would increase or decrease by approximately $9.1 million for each $1.00 per barrel change in crude oil prices and $1.7 million for each $0.10 per MMBtu change in natural gas prices.

To partially reduce price risk caused by these market fluctuations, we have occasionally hedged crude oil and natural gas prices in the past, through the utilization of derivatives, including zero-cost collars and fixed price contracts. Most recently, in July 2007, we entered into fixed-price swap contracts covering 10,000 barrels of oil per day for the period from August 2007 through April 2008. During 2008 and 2007, we had recognized losses on derivatives of $8.0 million and $44.9 million, respectively. These contracts expired in April 2008 and we currently have no hedges in place.

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

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leverage of the debt portfolio. We are exposed to changes in interest rates as a result of our revolving credit facility. We had total indebtedness of $474.4 million outstanding under our revolving credit facility at February 23, 2009. The impact of a 1% increase in interest rates on this amount of debt would result in increased interest expense of approximately $4.7 million and a $2.9 million decrease in net income. Our weighted average interest rate at December 31, 2008 was 4.11%. Our weighted average interest rate at February 23, 2009 was 3.57%. 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:

	2009	2010	2011	2012	2013	Total
			(in thousands)			
Variable rate debt:						
Revolving credit facility:						
Principal amount	$	$	$ 376.4	$	$	$ 376.4
Weighted-average interest rate			4.11%			4.11%

Item 8. Financial Statements and Supplemental Data

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REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

Board of Directors and Shareholders

Continental Resources, Inc.

We have audited the accompanying consolidated balance sheets of Continental Resources, Inc. (an Oklahoma corporation) and Subsidiary (the Company) as of December 31, 2008 and 2007, and the related consolidated statements of income, shareholders equity and cash flows for each of the three years in the period ended December 31, 2008. These financial statements are the responsibility of the Company s management. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, the consolidated financial statements referred to above present fairly, in all material respects, the financial position of Continental Resources, Inc. and Subsidiary as of December 31, 2008 and 2007, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2008 in conformity with accounting principles generally accepted in the United States of America.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), Continental Resources, Inc. and Subsidiary s internal control over financial reporting as of December 31, 2008, based on criteria established in *Internal Control Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO) and our report dated February 26, 2009 expressed an unqualified opinion.

/s/ GRANT THORNTON LLP

Oklahoma City, Oklahoma

February 26, 2009

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Continental Resources, Inc. and Subsidiary

Consolidated Balance Sheets

	December 31, 2008	December 31, 2007
	(In thousands, except par values and share data)	
Assets		
Current assets:		
Cash and cash equivalents	$ 5,229	$ 8,761
Receivables:		
Oil and natural gas sales	63,659	95,165
Affiliated parties	14,914	17,146
Joint interest and other, net	150,506	50,779
Inventories	22,210	19,119
Deferred and prepaid taxes	18,810	12,159
Prepaid expenses and other	2,367	2,435
Total current assets	277,695	205,564
Net property and equipment, based on successful efforts method of accounting	1,935,143	1,157,926
Debt issuance costs, net	3,041	1,683
Total assets	$ 2,215,879	$ 1,365,173
Liabilities and shareholders equity		
Current liabilities:		
Accounts payable trade	$ 260,188	$ 127,730
Accounts payable trade to affiliated parties	25,730	15,090
Accrued liabilities and other	34,769	25,295
Revenues and royalties payable	78,160	67,349
Unrealized derivative losses		26,703
Current portion of asset retirement obligation	4,747	3,939
Total current liabilities	403,594	266,106
Long-term debt	376,400	165,000
Other noncurrent liabilities:		
Deferred tax liability	445,752	271,424
Asset retirement obligation, net of current portion	39,883	38,153
Other noncurrent liabilities	1,542	1,358
Total other noncurrent liabilities	487,177	310,935
Commitments and contingencies (Note 10)		
Shareholders equity:		
Preferred stock, $0.01 par value: 25,000,000 shares authorized; no shares issued and outstanding		
Common stock, $0.01 par value; 500,000,000 shares authorized, 169,558,129 shares issued and outstanding at December 31, 2008; 168,864,015 shares issued and outstanding at December 31, 2007	1,696	1,689
Additional paid-in capital	420,054	415,435
Retained earnings	526,958	206,008
Total shareholders equity	948,708	623,132
Total liabilities and shareholders equity	$ 2,215,879	$ 1,365,173

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

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Continental Resources, Inc. and Subsidiary

Consolidated Statements of Income

	Year Ended December 31, 2008	2007	2006
	(In thousands, except per share data)		
Revenues:			
Oil and natural gas sales	$ 875,213	$ 572,610	$ 374,304
Oil and natural gas sales to affiliates	64,693	33,904	94,298
Loss on mark-to-market derivative instruments	(7,966)	(44,869)	
Oil and natural gas service operations	28,550	20,570	15,050
Total revenues	960,490	582,215	483,652
Operating costs and expenses:			
Production expenses	80,935	57,562	45,694
Production expense to affiliates	20,700	18,927	17,171
Production tax	58,610	32,562	22,331
Exploration expense	40,160	9,163	19,738
Oil and natural gas service operations	18,188	12,709	8,231
Depreciation, depletion, amortization and accretion	148,902	93,632	65,428
Property impairments	28,847	17,879	11,751
General and administrative	35,719	32,802	31,074
Gain on sale of assets	(894)	(988)	(290)
Total operating costs and expenses	431,167	274,248	221,128
Income from operations	529,323	307,967	262,524
Other income (expense):			
Interest expense	(12,188)	(12,939)	(11,310)
Other	1,395	1,749	1,742
	(10,793)	(11,190)	(9,568)
Income before income taxes	518,530	296,777	252,956
Provision (benefit) for income taxes	197,580	268,197	(132)
Net income	$ 320,950	$ 28,580	$ 253,088
Basic net income per share	$ 1.91	$ 0.17	$ 1.60
Diluted net income per share	$ 1.89	$ 0.17	$ 1.59
Dividends per share	$	$ 0.33	$ 0.55
Pro forma (unaudited, Note 1):			
Income before income taxes		$ 296,777	$ 252,956
Provision for income taxes		112,775	96,123
Net income		$ 184,002	$ 156,833
Basic net income per share		$ 1.12	$ 0.97
Diluted net income per share		$ 1.11	$ 0.96

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

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Continental Resources, Inc. and Subsidiary

Consolidated Statements of Shareholders Equity

	Shares outstanding	Common stock	Additional paid-in capital	Retained earnings	Accumulated other comprehensive income (loss)	Total shareholders equity
			(in thousands, except share data)			
Balance, January 1, 2006	159,048,626	$ 144	$ 27,087	$ 297,461	$ 38	$ 324,730
Comprehensive income:						
Net income				253,088		253,088
Other comprehensive income, net of tax					(63)	(63)
Total comprehensive income						253,025
Stock options:						
Exercised	22,660					
Restricted stock:						
Issued	200,772					
Repurchased and canceled	(60,665)					
Forfeited	(105,149)					
Dividends				(87,294)		(87,294)
Balance, December 31, 2006	159,106,244	$ 144	$ 27,087	$ 463,255	$ (25)	$ 490,461
Comprehensive income:						
Net income				28,580		28,580
Other comprehensive income, net of tax					25	25
Total comprehensive income						28,605
Public offering of common stock	8,850,000	89	124,406			124,495
Reclass for stock split		1,447	(1,447)			
Adjust for undistributed earnings from conversion to subchapter C corporation			234,099	(234,099)		
Reclass stock compensation liability to equity			29,828			29,828
Stock-based compensation			3,874			3,874
Tax benefit on share-based compensation plan			1,630			1,630
Stock options:						
Exercised	689,476	7	619			626
Repurchased and canceled	(292,313)	(3)	(3,079)			(3,082)
Restricted stock:						
Issued	629,684	6				6
Repurchased and canceled	(77,441)	(1)	(1,476)			(1,477)
Forfeited	(41,635)		(106)			(106)
Dividends				(51,728)		(51,728)
Balance, December 31, 2007	168,864,015	$ 1,689	$ 415,435	$ 206,008	$	$ 623,132
Net income				320,950		320,950
Stock-based compensation			9,927			9,927
Stock options:						
Exercised	436,327	4	1,438			1,442
Repurchased and canceled	(82,922)	(1)	(4,017)			(4,018)
Restricted stock:						
Issued	461,120	5				5
Repurchased and canceled	(91,568)	(1)	(2,729)			(2,730)
Forfeited	(28,843)					

Balance, December 31, 2008	169,558,129	$ 1,696	$ 420,054	$ 526,958	$	$ 948,708

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

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Continental Resources, Inc. and Subsidiary

Consolidated Statements of Cash Flows

	Year ended December 31,		
	2008	2007	2006
		(In thousands)	
Cash flows from operating activities:			
Net income	$ 320,950	$ 28,580	$ 253,088
Adjustments to reconcile net income to net cash provided by operating activities:			
Depreciation, depletion, amortization and accretion	148,573	95,604	65,540
Property impairments	28,847	17,879	11,751
Change in derivative fair value	(26,703)	26,703	
Equity compensation	9,081	12,791	10,932
Tax benefit of excess non qualified stock compensation deduction		(1,630)	
Provision for deferred income taxes	184,115	262,412	
Dry hole costs	20,002	3,549	13,344
Other, net	(114)	(331)	610
Changes in assets and liabilities:			
Accounts receivable	(65,989)	(74,004)	(11,739)
Inventories	(3,834)	(11,288)	(3,005)
Prepaid expenses and other	(16,520)	(2,837)	(386)
Accounts payable	101,967	(7,760)	77,422
Revenues and royalties payable	10,811	38,611	(2,917)
Accrued liabilities and other	8,545	2,009	2,297
Other noncurrent liabilities	184	360	104
Net cash provided by operating activities	719,915	390,648	417,041
Cash flows from investing activities:			
Exploration and development	(841,479)	(477,663)	(313,071)
Purchase of oil and gas properties	(74,662)	(4,166)	(6,564)
Purchase of other property and equipment	(14,651)	(4,610)	(6,944)
Proceeds from sale of assets	3,175	2,941	2,056
Net cash used in investing activities	(927,617)	(483,498)	(324,523)
Cash flows from financing activities:			
Revolving credit facility	443,000	288,500	286,000
Repayment of revolving credit facility	(231,600)	(263,500)	(289,000)
Proceeds from initial public offering, net		124,495	
Dividends to shareholders	(207)	(52,036)	(87,373)
Repurchase of equity grants	(6,748)	(5,075)	
Exercise of options	1,442	644	29
Tax benefit of excess non qualified stock compensation deduction		1,630	
Debt issuance costs	(1,717)	(90)	(1,107)
Net cash (used in) provided by financing activities	204,170	94,568	(91,451)
Effect of exchange rate changes on cash and cash equivalents		25	(63)
Net change in cash and cash equivalents	(3,532)	1,743	1,004
Cash and cash equivalents at beginning of period	8,761	7,018	6,014
Cash and cash equivalents at end of period	$ 5,229	$ 8,761	$ 7,018

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

Continental Resources, Inc. and Subsidiary

Notes to Consolidated Financial Statements

1. Organization and Summary of Significant Accounting Policies

Description of Company

Continental Resources, Inc. is incorporated under the laws of the State of Oklahoma. It was originally formed in 1967 to explore, develop and produce oil and natural gas properties in Oklahoma. Through 1993, its activities and growth remained focused primarily in Oklahoma. In 1993, the Company expanded its activity into the Rocky Mountain and Gulf Coast regions. Approximately 70% of its estimated proved reserves as of December 31, 2008 are located in the Rocky Mountain region. As of December 31, 2008, the Company had interests in 2,192 wells and serves as the operator of 1,657 of these wells.

On May 14, 2007, the Company completed its initial public offering. In conjunction therewith, the Company effected an 11 for 1 stock split by means of a stock dividend. All prior period share and per share information contained in this report has been retroactively restated to give effect to the stock split. On May 14, 2007, the Company amended its certificate of incorporation to, among other things, increase the number of authorized preferred shares to 25 million and common shares to 500 million. Prior to completion of the public offering, the Company was a subchapter S corporation and income taxes were payable by its shareholders. In connection with the public offering, the Company converted to a subchapter C corporation.

Basis of presentation

Continental had one wholly owned subsidiary, Continental Resources of Illinois, Inc. (CRII) at December 31, 2005. CRII was incorporated in June 2001 for the purpose of acquiring the assets of Farrar Oil Company and Har-Ken Oil Company. Continental acquired Banner Pipeline Company, L.L.C. (Banner) on March 30, 2006 for approximately $8.8 million, which represented the book value of working capital, principally cash, accounts receivable, crude oil inventory and accounts payable. CRII was merged into Continental on October 12, 2006. Banner was Continental s only subsidiary at December 31, 2007 and 2008.

All significant inter-company accounts and transactions have been eliminated in the consolidated financial statements.

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

Pro forma information (unaudited)

Pro forma adjustments are reflected on the consolidated statements of income to provide for income taxes in accordance with Statement of Financial Accounting Standards (SFAS) No. 109 Accounting for Income Taxes as if the Company had been a subchapter C corporation for all pro forma periods presented. For unaudited pro forma income tax calculations, deferred tax assets and liabilities were recognized for the future tax consequences attributable to differences between the financial statement carrying amounts of existing assets and liabilities and their respective tax basis. Deferred tax assets and liabilities were measured using enacted tax rates expected to apply to taxable income in the years in which the Company expects to recover or settle those temporary differences. A statutory Federal tax rate of 35% and effective state tax rate of 3% (net of Federal

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Continental Resources, Inc. and Subsidiary

Notes to Consolidated Financial Statements (continued)

income tax effects) were used for the pro forma enacted tax rate for all periods. The pro forma tax effects are based upon currently available information. Management believes that these assumptions provide a reasonable basis for representing the pro forma tax effects.

The pro forma information should be read in conjunction with the related historical information and is not necessarily indicative of the results that would have been attained had the transactions actually taken place.

Revenue recognition

Oil and natural gas sales result from interests owned by the Company in oil and natural gas properties. Sales of oil and natural gas produced from oil and natural gas operations are recognized when the product is delivered to the purchaser and title transfers to the purchaser. The Company uses the sales method of accounting for natural gas imbalances in those circumstances where it has under-produced or over-produced its ownership percentage in a property. Under this method, a receivable or liability is recognized only to the extent that an imbalance cannot be recouped from the reserves in the underlying properties. The Company s aggregate imbalance positions at December 31, 2008 and 2007 were not material. Charges for gathering and transportation are included in production expenses.

Cash and cash equivalents

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

Accounts receivable

The Company operates exclusively in oil and natural gas exploration and production related activities. Oil and natural gas sales and joint interest receivables are generally unsecured. Accounts receivable are due within 30 days and considered delinquent after 60 days. The Company determines its allowance for doubtful accounts by considering a number of factors, including the length of time accounts are past due, the Company s loss history, and the customer or working interest owner s ability to pay. The Company writes off specific accounts when they become uncollectible and any payments subsequently received on these receivables are credited to the allowance for doubtful accounts. The following table presents the allowance for doubtful accounts at December 31, 2008, 2007 and 2006 and changes in the allowance for these years:

	Balance at beginning of period	Additions charged to costs and expenses	Deductions	Balance at end of period
Year ended December 31, 2008	$ 193,326	$	$ (200)	$ 193,126
Year ended December 31, 2007	193,326			193,326
Year ended December 31, 2006	171,451	68,178	(46,303)	193,326

Concentration of credit risk

The Company is subject to credit risk resulting from the concentration of its crude oil and natural gas receivables with several significant customers. The largest purchasers of the Company s oil and gas production accounted for 44% (one purchaser), 44% (three purchasers) and 33% (two purchasers) of total revenues for 2008, 2007 and 2006, respectively. These purchasers constituted all purchasers with sales in excess of 10% of total

Continental Resources, Inc. and Subsidiary

Notes to Consolidated Financial Statements (continued)

revenues. The Company does not require collateral and does not believe the loss of any single purchaser would materially impact its operating results, as oil and natural gas are fungible products with well-established markets and numerous purchasers.

Inventories

Inventories are stated at the lower of cost or market. Inventory consists primarily of tubular goods and production equipment, which totaled approximately $14.9 million and $4.7 million at December 31, 2008 and 2007, respectively, and crude oil line fill and temporary storage of approximately $7.3 million, representing 275,000 barrels of crude oil, and $14.4 million, representing 384,000 barrels of crude oil, at December 31, 2008 and 2007, respectively.

Property and equipment

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

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

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

Oil and gas properties

The Company uses the successful efforts method of accounting for oil and gas properties whereby costs to acquire mineral interests in oil and gas properties, drill and equip exploratory wells that find proved reserves and to drill and equip development wells are capitalized. Geological and geophysical costs, seismic costs, lease rentals and costs associated with unsuccessful exploratory wells are expensed as incurred. Maintenance and repairs are expensed as incurred, except that the cost of replacements or renewals that expand capacity or improve production are capitalized.

The Company reports capitalized exploratory drilling costs on the balance sheet according to SFAS No. 19, Financial Accounting and Reporting by Oil and Gas Producing Companies . On a monthly basis, the Company capitalizes the costs of drilling exploratory wells pending determination of whether the well has found proved reserves. The Company capitalizes costs associated with the acquisition or construction of support equipment and facilities with the drilling and development costs to which they relate. If proved reserves are found by an exploratory well, associated capitalized costs become part of well equipment and facilities. However, if proved reserves are not found, the capitalized costs associated with the well are expensed, net of any salvage value. Total capitalized exploratory drilling costs, as of December 31, 2008 and 2007, pending the determination of proved reserves were $46.3 million and $32.9 million, respectively. As of December 31, 2008, exploratory drilling costs of $0.2 million representing three wells were suspended beyond one year and are expected to be fully evaluated in 2009. Of the suspended costs, $0.1 million was incurred in 2007 and the balance in 2008. All three projects were drilled in 2007.

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Continental Resources, Inc. and Subsidiary

Notes to Consolidated Financial Statements (continued)

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

The Company accounts for its asset retirement obligations pursuant to SFAS No. 143, Accounting for Asset Retirement Obligations which requires entities to record the fair value of a liability for an asset retirement obligation in the period in which it is incurred and a corresponding increase in the carrying amount of the related long-lived asset. Subsequently, the asset retirement costs are charged to expense through the depreciation, depletion and amortization of oil and gas properties and the liability is accreted to the expected abandonment amount over the asset s life.

The Company s primary asset retirement obligations relate to future plugging and abandonment expenses on its oil and natural gas properties and related facilities disposal. The following table summarizes the changes in the Company s future abandonment liability from January 1, 2006 through December 31, 2008 (in thousands):

	2008	2007	2006
Asset retirement obligation liability at January 1,	$ 42,092	$ 41,273	$ 34,353
Asset retirement obligation accretion expense	2,053	1,962	1,680
Plus: Revisions	(117)	(1,817)	4,391
Additions for new assets	3,900	2,453	2,480
Less: Plugging costs and sold assets	(3,298)	(1,779)	(1,631)
Asset retirement obligation liability at December 31,	$ 44,630	$ 42,092	$ 41,273

As of December 31, 2008 and 2007, property and equipment included $30.5 million and $27.5 million, respectively, of net asset retirement costs.

Depreciation, depletion, amortization and accretion

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

Impairment

Non-producing properties consist of undeveloped leasehold costs and costs associated with the purchase of proved undeveloped reserves. Individually significant non-producing properties are periodically assessed for impairment of value and a loss is recognized at the time of impairment. Other non-producing properties are amortized on a composite method based on the Company s estimated experience of successful drilling and the average holding period. Impairment of non-producing properties was $16.6 million, $13.2 million and $5.4 million for 2008, 2007, and 2006 respectively.

Continental Resources, Inc. and Subsidiary

Notes to Consolidated Financial Statements (continued)

In accordance with the provisions of SFAS No. 144, Accounting for the Impairment or Disposal of Long-Lived Assets , the Company recognizes impairment expenses for developed oil and gas properties and other long-lived assets when indicators of impairment are present and the undiscounted cash flows from proved and risk-adjusted probable reserves are not sufficient to recover the assets carrying amount. The impairment loss is measured by comparing the fair value of the asset to its carrying amount. Fair values are based on discounted future cash flows. The Company s oil and gas properties are reviewed for indicators of impairment on a field-by-field basis, resulting in the recognition of impairment provisions of $12.3 million, $4.7 million and $6.3 million, respectively, for 2008, 2007 and 2006. The majority of the impairment recognized in these years relates to fields comprised of a small number of properties or single wells on which the Company does not expect sufficient future net cash flows to recover its carrying cost.

Debt issuance costs

Costs incurred in connection with the issuance of long-term debt are capitalized and amortized over the term of the related debt. The Company had capitalized costs of $2.8 million and $1.7 million (net of accumulated amortization of $5.6 million and $5.0 million) relating to the issuance of its long-term debt at December 31, 2008 and 2007, respectively. During the years ended December 31, 2008, 2007 and 2006, the Company recognized associated amortization expense of $0.6 million, $0.6 million and $0.9 million, respectively. Debt issuance costs are capitalized and amortized on a straight-line basis, the use of which approximates the effective interest method, over the life of the revolving credit facility.

Derivatives

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

Fair value of financial instruments

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

The fair value of long-term debt approximates its carrying value based on the borrowing rates currently available to the Company for bank loans with similar terms and maturities. The estimated fair value of long-term debt is $376.4 million and $165.0 million at December 31, 2008 and 2007, respectively.

Income taxes

On May 14, 2007, the Company completed its initial public offering. Prior to completion of the public offering, the Company was a subchapter S corporation and income taxes were payable by its shareholders. In connection with the public offering, the Company converted to a subchapter C corporation and recorded a charge to income in the second quarter of 2007 of $198.4 million to initially recognize deferred taxes at May 14, 2007. Thereafter, the Company has provided for income taxes on income. In 2005, the Company recorded federal income tax expense of $1.1 million attributable to gains on sales of properties where the fair market value at the date of conversion into a subchapter S corporation exceeded their tax basis and the properties were sold within 10 years of the conversion in accordance with section 1374 of the Internal Revenue Code. The benefit recorded during 2006 reflects a change in estimate of the original provision recorded.

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Continental Resources, Inc. and Subsidiary

Notes to Consolidated Financial Statements (continued)

Income taxes are accounted for using the liability method under which deferred income taxes are recognized for the future tax effects of temporary differences between the financial statement carrying amounts and the tax basis of existing assets and liabilities using the enacted statutory tax rates in effect at year-end. The effect on deferred taxes for a change in tax rates is recognized in income in the period that includes the enactment date. A valuation allowance for deferred tax assets is recorded when it is more likely than not that the benefit from the deferred tax asset will not be realized.

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

Equity compensation

The Company accounts for employee stock option grants and restricted stock grants in accordance with SFAS 123(R). The terms of the restricted stock and stock option grants stipulated that, prior to its initial public offering, the Company was required to purchase vested restricted stock and stock acquired from stock option exercises at each employee s request based upon the purchase price as determined by a formula specified in each award agreement. Additionally, the Company had the right to purchase vested restricted stock and stock acquired from stock option exercises at the same price upon termination of employment for any reason and for a period of two years subsequent to leaving the employment of the Company. Therefore, the awards were accounted for as liability awards in accordance with SFAS 123(R). The Company measured compensation cost for the awards based upon fair value. Restricted stock and stock option values represent intrinsic value prior to 2006 and fair value after March 6, 2006, when the Company became a public entity under SFAS 123(R). Fair value of stock options is determined using the Black-Scholes option valuation model.

The right to sell and requirement to purchase lapsed when the Company became a reporting company under Section 12 of the Exchange Act. Therefore, the liability for equity compensation was reclassified to additional paid in capital in May 2007.

Continental Resources, Inc. and Subsidiary

Notes to Consolidated Financial Statements (continued)

Earnings per common share

Basic earnings per common share is computed by dividing net income by the weighted-average number of shares outstanding for the period. Diluted earnings per share reflects the potential dilution of non-vested restricted stock awards and dilutive stock options, which are calculated using the treasury stock method as if these options were exercised. The following is the calculation of basic and diluted weighted average shares outstanding and earning per share computations for the years ended December 31, 2008, 2007 and 2006:

	2008	2007	2006
	(in thousands, except per share data)		
Income (numerator):			
Net income basic and diluted	$ 320,950	$ 28,580	$ 253,088
Weighted average shares (denominator):			
Weighted average shares basic	168,087	164,059	158,114
Restricted stock	686	211	300
Employee stock options	619	1,152	1,251
Weighted average shares diluted	169,392	165,422	159,665
Earnings per share:			
Basic	$ 1.91	$ 0.17	$ 1.60
Diluted	$ 1.89	$ 0.17	$ 1.59

Comprehensive income

The Company classifies other comprehensive income (loss) items by their nature in the consolidated financial statements and displays the accumulated balance of other comprehensive income (loss) separately in the shareholders equity section of the balance sheet.

Recent accounting pronouncements

In December 2007, the FASB issued SFAS No. 141 (revised 2007), Business Combinations (SFAS 141(R)) and SFAS No. 160, Noncontrolling Interests in Consolidated Financial Statements, an amendment of ARB No. 51 (SFAS 160). SFAS 141(R) will change how business acquisitions are accounted for and will impact financial statements both on the acquisition date and in subsequent periods. SFAS 160 will change the accounting and reporting for minority interests, which will be re-characterized as noncontrolling interests and classified as a component of equity. SFAS 141(R) and SFAS 160 are effective for the Company for fiscal years beginning on or after December 15, 2008. SFAS 141(R) will be applied prospectively. SFAS 160 requires retroactive adoption of the presentation and disclosure requirements for existing minority interests. All other requirements of SFAS 160 will be applied prospectively. Early adoption is prohibited for both standards. The adoption of SFAS 141(R) and SFAS 160 is not expected to have a material impact on the Company s consolidated financial position or results of operations.

In February 2008, the FASB issued FASB Staff Position FAS 157-2, *Effective Date of FASB Statement No. 157,* which provides a one year delay of the effective date of FAS 157 to January 1, 2009 for the Company for non-financial assets and non-financial liabilities, except those that are recognized or disclosed at fair value in the financial statements on a recurring basis (at least annually). The impact of adoption related to the non-financial assets and liabilities will depend on the Company s assets and liabilities at the time they are required to be measured at fair value.

In March 2008, the FASB issued SFAS No. 161, *Disclosures about Derivative Instruments and Hedging Activities an amendment of FASB Statement No. 133,* which amends and expands the disclosure requirements of

Continental Resources, Inc. and Subsidiary

Notes to Consolidated Financial Statements (continued)

FAS 133 to require qualitative disclosure about objectives and strategies for using derivatives, quantitative disclosures about fair value amounts of gains and losses on derivative instruments, and disclosures about credit-risk-related contingent features in derivative agreements. This statement will be effective for the Company beginning in fiscal 2009. The adoption of this statement will change the disclosures related to derivative instruments held by the Company, if any.

In May 2008, the FASB issued SFAS No. 162, *The Hierarchy of Generally Accepted Accounting Principles* (SFAS 162), which identifies the sources of accounting principles and the framework for selecting the principles to be used in preparation of financial statements of nongovernmental entities that are presented in conformity with generally accepted accounting principles in the United States of America. SFAS 162 was adopted by the Company effective November 15, 2008. SFAS 162 did not have a material impact on the Company s consolidated financial position or results of operations.

On December 29, 2008, the Securities and Exchange Commission announced final approval of new requirements, effective for annual reports on Form 10-K for fiscal years ending on or after December 31, 2009, to provide investors with a more meaningful and comprehensive understanding of oil and natural gas reserves. The new disclosure requirements include:

- Consideration of new technologies in evaluating oil and natural gas reserves,
- Disclosure of probable and possible oil and natural gas reserves,
- Use of an average price based on the prior twelve month period rather than year-end prices, and
- Revisions of the oil and natural gas disclosure requirements for operations.

The Company has not yet evaluated the effects of the above on its financial statements and disclosures.

2. Cash Flow Information

Net cash provided by operating activities reflects cash payments as follows (in thousands):

	Year Ended December 31,		
	2008	2007	2006
Interest paid	$ 10,224	$ 11,499	$ 10,875
Income taxes paid	31,560	6,988	1,007

Noncash investing and financing activities are as follows (in thousands):

	Year Ended December 31,		
	2008	2007	2006
Asset retirement obligations	$ 3,783	$ 636	$ 6,871

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Continental Resources, Inc. and Subsidiary

Notes to Consolidated Financial Statements (continued)

3. Property, Plant, and Equipment

Property, plant and equipment includes the following at December 31, 2008 and 2007 (in thousands):

	December 31, 2008	December 31, 2007
Proved oil and natural gas properties	$ 2,250,757	$ 1,518,981
Unproved oil and natural gas properties	248,689	65,830
Service properties, equipment and other	42,720	29,000
Total property and equipment	2,542,166	1,613,811
Accumulated depreciation, depletion and amortization	(607,023)	(455,885)
Net property and equipment	$ 1,935,143	$ 1,157,926

4. Accrued Liabilities and Other

Accrued liabilities and other includes the following at December 31, 2008 and 2007 (in thousands):

	December 31, 2008	December 31, 2007
Prepaid drilling costs	$ 14,742	$ 4,002
Accrued compensation	6,057	5,604
Accrued production and advalorem taxes	10,532	10,805
Other	3,438	4,884
	$ 34,769	$ 25,295

5. Derivative Contracts

In July 2007, the Company entered into fixed-price swap contracts covering 10,000 barrels of oil per day for the period from August 2007 through April 2008 to partially reduce price risk. During each month of the contract, the Company received a fixed-price of $72.90 per barrel and paid to the counterparties the average of the prompt NYMEX crude oil futures contract settlement prices for such month. SFAS No. 133, *Accounting for Derivative Instruments and Hedging Activities* requires recognition of all derivative instruments on the balance sheet as either assets or liabilities measured at fair value. The Company elected not to designate its derivatives as cash flow hedges under the provisions of SFAS No. 133. As a result, the Company marked its derivative instruments to fair value in accordance with the provisions of SFAS No. 133 and recognized the realized and unrealized change in fair value on derivative instruments in the statements of income. As of December 31, 2007 the Company had recorded a liability for unrealized losses on derivatives of $26.7 million. For the year ended December 31, 2008, the statement of income contains recognized losses of $8.0 million for the contracts that expired in April 2008. For the year ended December 31, 2007, the statement of income contains realized losses of $18.2 million and unrealized losses of $26.7 million on derivatives. The Company did not have any derivative contracts in 2006 or at December 31, 2008.

Continental Resources, Inc. and Subsidiary

Notes to Consolidated Financial Statements (continued)

6. Fair Value Measures

The Company adopted SFAS No. 157, Fair Value Measurements, effective January 1, 2008 for financial assets and liabilities measured on a recurring basis. SFAS No. 157 applies to all financial assets and financial liabilities that are being measured and reported on a fair value basis. In February 2008, the FASB issued FASB Staff Position FAS 157-2, which delayed the effective date of SFAS No. 157 by one year for non-financial assets and liabilities. As defined in SFAS No. 157, fair value is the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants at the measurement date. SFAS No. 157 requires disclosure that establishes a framework for measuring fair value and expands disclosure about fair value measurements. The statement requires fair value measurements be classified and disclosed in one of the following categories:

Level 1: Unadjusted quoted prices in active markets that are accessible at the measurement date for identical, unrestricted assets or liabilities. We consider active markets as those in which transactions for the assets or liabilities occur in sufficient frequency and volume to provide pricing information on an ongoing basis.

Level 2: Quoted prices in markets that are not active, or inputs which are observable, either directly or indirectly, for substantially the full term of the asset or liability. This category includes those derivative instruments that we value using observable market data. Substantially all of these inputs are observable in the marketplace throughout the full term of the derivative instrument, can be derived from observable data, or supported by observable levels at which transactions are executed in the marketplace. Instruments in this category include non-exchange traded derivatives such as over-the-counter commodity price swaps.

Level 3: Measures based on prices or valuation models that require inputs that are both significant to the fair value measurement and less observable from objective sources (i.e., supported by little or no market activity).

As required by SFAS No. 157, financial assets and liabilities are classified based on the lowest level of input that is significant to the fair value measurement. Our assessment of the significance of a particular input to the fair value measurement requires judgment, and may affect the valuation of the fair value of assets and liabilities and their placement within the fair value hierarchy levels.

During the year ended December 31, 2008, the Company valued its derivative instruments according to SFAS No. 157 pricing levels. These contracts expired during the second quarter of 2008 and the Company currently does not have any financial assets or financial liabilities that are measured on a fair value basis.

7. Long-term Debt

The Company had $376.4 million and $165.0 million in long-term debt outstanding at December 31, 2008 and 2007, respectively, on its revolving credit facility due April 11, 2011. At the Company s election, the maturity date can be extended for up to two one-year periods. The Company amended its revolving credit facility in the fourth quarter of 2008 to increase the associated commitment level to $552.5 million and to revise the London Interbank Offered Rate margins to a range of 175 to 250 basis points. Additionally, the Company elected to set the revolving credit facility borrowing base at $850.0 million. Borrowings under the facility bear interest, payable quarterly, at a rate per annum equal to the London Interbank Offered Rate for one, two, three or six months, as elected by the Company, plus a margin ranging from 175 to 250 basis points, depending on the percentage of its borrowing base utilized, or the lead bank s reference rate. The revolving credit facility has a maximum facility amount of $750.0 million, a borrowing base of $850.0 million, subject to semi-annual re-determination, and a commitment level of $552.5 million at December 31, 2008. Under the terms of the revolving credit facility, the commitment level can be increased up to the lesser of the borrowing base or the note

Continental Resources, Inc. and Subsidiary

Notes to Consolidated Financial Statements (continued)

amount subject to bank agreement. Borrowings under the revolving credit facility are secured by liens on substantially all oil and gas properties and associated assets of the Company. In February 2009, the Company amended the revolving credit facility to add additional banks and increase the commitments to $672.5 million.

The Company had $176.1 million of unused commitments under the Credit Agreement at December 31, 2008 and incurs commitment fees of 0.25% to 0.375% of the daily average excess of the commitment amount over the outstanding credit balance. The revolving credit facility contains certain covenants including that the Company maintain a current ratio of not less than 1.0 to 1.0 (inclusive of availability under the Credit Agreement) and a Total Funded Debt to EBITDAX, as defined, of no greater than 3.75 to 1.0. The Company was in compliance with these covenants at December 31, 2008.

The Company s weighted average interest rate was 4.11% and 6.26% at December 31, 2008 and 2007, respectively. At December 31, 2008, the Company had $0.8 million of outstanding letters of credit that expire during 2009.

8. Income Taxes

The following is an analysis of the Company s income tax provision in conjunction with and subsequent to the conversion to a subchapter C corporation on May 14, 2007. Prior to this date, the Company was a subchapter S corporation and income taxes were payable by its shareholders.

	Year ended December 31,	
	2008	2007
	(in thousands)	
Current:		
Federal	$ 13,465	$ 5,785
State		
Total current tax provision	13,465	5,785
Deferred:		
Federal	164,929	233,801
State	19,186	28,611
Total deferred tax provision	184,115	262,412
Income tax provision	$ 197,580	$ 268,197

The following table reconciles the income tax provision with income tax at the Federal statutory rate for the years ended December 31, 2008 and 2007.

	Year ended December 31,	
	2008	2007
	(in thousands)	
Federal tax at statutory rate	$ 181,486	$ 103,872
State income taxes, net of federal benefit	17,146	7,716
Eliminate taxes on earnings prior to subchapter C corporation conversion[(1)]		(32,380)
Non-deductible stock-based compensation	15	1,090
Other, net	(1,067)	1,770

Earnings transferred to subchapter S corporation through election of pro-rata allocation method[2]		(12,275)
Deferred taxes recorded upon conversion to a subchapter C corporation		198,404
Income tax provision	$ 197,580	$ 268,197

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Continental Resources, Inc. and Subsidiary

Notes to Consolidated Financial Statements (continued)

(1) Federal tax at the statutory rate and state income taxes have been calculated based upon the net income before tax for the year. However, the Company converted from a subchapter S corporation to a subchapter C corporation on May 14, 2007 and deferred taxes were provided for temporary differences that existed on that date. This adjustment eliminates the taxes related to the net income before tax from the beginning of the year presented through May 14, 2007, which tax effects are already included in deferred taxes recorded upon conversion to a subchapter C corporation.

(2) The Company calculated its estimate of income allocation to the subchapter S corporation period assuming the use of the pro-rata income allocation method for tax purposes instead of the specific identification method used for financial reporting purposes. Using the pro-rata income allocation method, the Company s income for the year is allocated to the subchapter S corporation and the subchapter C corporation based on number of days without regard to when the income was actually earned.

Significant components of the Company s deferred tax assets and liabilities as of December 31, 2008 are as follows:

	December 31, 2008	2007
	(in thousands)	
Current:		
Deferred tax assets[1]		
Unrealized losses on derivatives	$	$ 10,040
Other expenses	715	602
Total current deferred tax assets	715	10,642
Noncurrent:		
Deferred tax assets		
Net operating loss carryforward	8,087	4,553
Alternative minimum tax carryforward	19,858	6,537
Deferred compensation		1,952
Other	958	438
Total noncurrent deferred tax assets	28,903	13,480
Deferred tax liabilities		
Property and equipment	473,387	284,904
Deferred compensation	1,268	
Total noncurrent deferred tax liabilites	474,655	284,904
Net noncurrent deferred tax liabilities	445,752	271,424
Net deferred tax liabilities	$ 445,037	$ 260,782

(1) Deferred and prepaid taxes on the accompanying consolidated balance sheet at December 31, 2008 contains a receivable of $18.1 million for overpaid taxes and at December 31, 2007 contained prepaid taxes of $1.2 million.

As of December 31, 2008, the Company had a net operating loss carryforward of $34.6 million which will expire beginning in 2027. Included in the net operating loss carryforward is excess tax benefit related to stock compensation of $13.3 million ($5.0 million tax effected) for which the deferred tax asset cannot be recorded until the Company is paying regular federal income taxes. When recorded, the offsetting account will be additional paid-in capital. In addition, the Company has an alternative minimum tax credit carryforward of $19.9 million and a statutory depletion carryforward, which will be recognized when realized, of $4.4 million, neither

Continental Resources, Inc. and Subsidiary

Notes to Consolidated Financial Statements (continued)

of which expires. The Company s major tax jurisdictions are the U. S. Federal, Oklahoma, North Dakota and Montana. The earliest year subject to examination in each is 2003. However, prior to May 15, 2007, the Company was an S corporation and any taxes for periods prior to that would be payable by the then existing shareholders.

9. Lease Commitments

Lease expense associated with the Company s operating leases for the years ended December 31, 2008, 2007 and 2006, was $6.0 million, $6.0 million and $5.9 million, respectively. At December 31, 2008, including leases renewed and entered into subsequent to December 31, 2008, the minimum future rental commitments under operating leases having non-cancelable lease terms in excess of one year, including leases from related parties, are as follows (in thousands):

Year	Leases with related parties	Leases with unrelated parties	Total amount
2009	$ 1,324	$ 165	$ 1,489
2010	156	84	240
2011		25	25
2012		4	4
2013			
Total obligations	$ 1,480	$ 278	$ 1,758

The Company leases compressors from a related party for approximately $400,000 per month under an operating lease. The term of the operating lease was through January 28, 2009 and is continuing on a month to month basis while a new agreement is being negotiated. The Company leases office space under operating leases from the principal shareholder (see Note 11).

10. Commitments and Contingencies

Drilling Commitments. As of December 31, 2008, the Company had contracts with various drilling contractors to use six drilling rigs with terms that expire through April 2011. These commitments are not recorded in the accompanying consolidated balance sheets. Future commitments as of December 31, 2008 are $11.5 million for contracts that expire in 2009 and $23.5 million for contracts that expire in 2011.

Employee retirement plan. The Company maintains a defined contribution retirement plan for its employees and makes discretionary contributions to the plan based on a percentage of each eligible employee s compensation. During 2008, 2007 and 2006, contributions to the plan were 5% of eligible employees compensation, excluding bonuses. Expense for the years ended December 31, 2008, 2007 and 2006, was $1.1 million, $0.9 million and $0.8 million, respectively.

Employee health claims. The Company self insures employee health claims up to the first $125,000 per employee. The Company self insures employee workers compensation claims up to the first $250,000 per employee. Any amounts paid above these are reinsured through third-party providers. The Company accrues for claims that have been incurred but not yet reported based on a review of claims filed versus expected claims based on claims history. At December 31, 2008 and 2007, the accrued liability for health and worker s compensation claims was $873,000 and $758,000, respectively.

Litigation. The Company is involved in various legal proceedings in the normal course of business, none of which, in the opinion of management, will have a material adverse effect on the financial position or results of

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Continental Resources, Inc. and Subsidiary

Notes to Consolidated Financial Statements (continued)

operations of the Company. As of December 31, 2008 and 2007, the Company has provided a reserve of $1.2 million and $1.0 million, respectively, for various matters none of which are believed to be individually significant.

Environmental Risk. Due to the nature of the oil and gas business, the Company is exposed to possible environmental risks. The Company is not aware of any material environmental issues or claims.

11. Related Party Transactions

The Company currently markets a portion of its natural gas sales to an affiliate. Prior to February 2006, the Company marketed a portion of its oil sales to an affiliate. During the years ended December 31, 2008, 2007, and 2006, these sales were approximately $64.7 million, $33.9 million, and $94.3 million. The Company also contracts for field services such as compression and drilling rig services and purchases residue fuel gas and reclaimed oil from certain affiliates. Production expense attributable to these affiliates was $20.7 million, $18.9 million and $17.2 million for the years ended December 31, 2008, 2007 and 2006, respectively. The total amount paid to these companies, a portion of which was billed to other interest owners, was approximately $104.1 million, $76.3 million and $52.9 million during the years ended December 31, 2008, 2007 and 2006, respectively. The Company operated crude oil gathering lines in North Dakota and Wyoming on behalf of an affiliated company for which they paid the Company approximately $332,000 and $346,000 during 2008 and 2007, respectively. At December 31, 2008 and 2007, approximately $14.9 million and $17.1 million was due from affiliates and approximately $25.7 million and $15.1 million was due to affiliates, respectively.

Certain officers of the Company own or control entities that own working and royalty interest in wells operated by the Company. The Company paid revenues, including royalties, of approximately $16.7 million, $10.4 million, and $7.9 million and billed expenses of $14.2 million, $9.1 million, and $5.2 million during the years ended December 31, 2008, 2007, and 2006, respectively, to these affiliates. The Company also paid them $157,000 in 2008 and $199,000 in 2007 for their share of undeveloped leasehold sales.

The Company leases office space under an operating lease from a company owned by the Company s principal shareholder. Rents paid associated with this lease totaled approximately $804,000, $707,000 and $638,000 for the years ended December 31, 2008, 2007 and 2006, respectively. The term of the lease is through February 2010 at an annual rate of approximately $937,000.

Under a contract for gas sales to an affiliate the Company pays for gathering and treating fees which amounted to $1.0 million in 2008 and $1.1 million in 2007.

12. Shareholders Equity

On May 14, 2007, the Company completed its initial public offering of 29,500,000 shares of its common stock at $15.00 per share. The shares are listed on the New York Stock Exchange under the symbol CLR. The Company sold 8,850,000 shares of common stock in the offering and Harold G. Hamm, the Chairman and Chief Executive Officer and principal shareholder of the Company, sold 20,650,000 shares of common stock in the offering. The offering generated gross proceeds of $132.8 million to the Company. The Company incurred underwriters discounts of approximately $8.0 million and other expenses of approximately $2.3 million. The Company netted an additional $290,000, representing 30% of the legal, accounting and other costs incurred by the Company after the Company decided to participate in the offering, against the proceeds of the offering. The balance of the offering costs were expensed as incurred. After the payment of offering expenses, the net proceeds were used to repay a portion of the outstanding indebtedness under the revolving credit facility.

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Notes to Consolidated Financial Statements (continued)

On May 14, 2007, the Company effected an 11 for 1 stock split by means of a stock dividend. All prior period share and per share information contained in these consolidated financial statements has been retroactively restated to give effect to the stock split. On May 14, 2007, the Company amended its certificate of incorporation to, among other things, increase the number of authorized preferred shares to 25 million and common shares to 500 million.

On May 14, 2007 the Company converted from a subchapter S corporation to a subchapter C corporation. As a result, the Company recorded an adjustment in the amount of $234.1 million to reduce retained earnings to $65.1 million as of the conversion date, which represents the retained earnings balance of the Company when it originally converted from a subchapter C corporation to a subchapter S corporation in May 1997. The amount of the adjustment represents undistributed earnings of $432.5 million, net of the related provision for deferred income taxes of $198.4 million which was included in the determination of net income for the year ended December 31, 2007.

The Company accounts for stock option grants and restricted stock grants in accordance with SFAS 123(R). The terms of the restricted stock grants and stock option grants stipulated that prior to the Company s initial public offering, it was required to purchase the vested restricted stock and stock acquired from stock option exercises at each employee s request. Therefore, the awards were accounted for as liability awards in accordance with SFAS 123(R). The right to sell and requirement to purchase lapsed when the Company completed its initial public offering. Therefore, the liability for equity compensation of approximately $29.8 million was reclassified to additional paid-in capital on May 14, 2007.

During 2008, the Company paid cash dividends of $207,000 upon vesting of restricted stock granted prior to dividend declaration in 2007.

On January 10, 2007 and March 6, 2007, the Company declared cash dividends of approximately $18.8 million and $33.3 million to its shareholders for tax purposes and, subject to forfeiture, to holders of unvested restricted stock. During 2007, the Company paid cash dividends of $52.0 million.

During 2006, the Company declared cash dividends totaling $87.6 million to existing shareholders and, subject to forfeiture, to holders of unvested restricted stock. During 2006, the Company paid cash dividends of $87.4 million.

13. Stock Compensation

The Company has granted stock options and restricted stock to employees and directors pursuant to the Continental Resources, Inc. 2000 Stock Option Plan (2000 Plan) and the Continental Resources, Inc. 2005 Long-Term Incentive Plan (2005 Plan) as discussed below. Pursuant to the award agreements, the Company had the right to purchase vested restricted shares and shares acquired by option exercise at all times the employee remained in the employment of the Company and for a period of two years subsequent to leaving the employment of the Company and grantees had the right to require the Company to purchase vested restricted shares and shares acquired by option exercise, each at a purchase price as determined by a formula specified in each award agreement, prior to completion of its initial public offering in May 2007. All grants of stock options were issued with an exercise price equal to the then estimated fair value of the Company s stock determined according to the plans. Before becoming a public reporting entity, the awards were accounted for as liability awards. The associated liability was transferred to additional paid in capital in May 2007 when the purchase rights lapsed. The Company s associated compensation expense included in general and administrative expense was $9.1 million, $12.8 million and $10.9 million during 2008, 2007 and 2006, respectively.

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Continental Resources, Inc. and Subsidiary

Notes to Consolidated Financial Statements (continued)

Stock Options

Effective October 1, 2000, the Company adopted the 2000 Plan and granted options to eligible employees. These grants consisted of either incentive stock options, nonqualified stock options or a combination of both. The granted stock options vest ratably over either a three or five-year period commencing on the first anniversary of the grant date and expire ten years from date of grant. On November 10, 2005, the 2000 Plan was terminated. As of December 31, 2008, options covering 1,863,463 shares had been exercised and 448,572 had been cancelled.

The Company s stock option activity under the 2000 Plan from December 31, 2005 to December 31, 2008 was as follows:

	Outstanding		Exercisable	
	Number of options	Weighted average exercise price	Number of options	Weighted average exercise price
Outstanding December 31, 2005	1,672,000	$ 2.13	1,206,337	$ 1.14
Exercised	(22,660)	1.26		
Canceled	(73,337)	3.97		
Outstanding December 31, 2006	1,576,003	2.06	1,370,666	1.59
Exercised	(689,476)	1.66		
Outstanding December 31, 2007	886,527	2.28	794,853	1.88
Exercised	(436,327)	3.31		
Outstanding December 31, 2008	450,200	1.28	450,200	1.28

The total intrinsic value of options exercised during the years ended December 31, 2008, 2007 and 2006 was $15.1 million, $11.1 million and $0.1 million, respectively. The intrinsic value of a stock option is the amount by which the value of the underlying stock exceeds the exercise price of the option at its exercise date. At December 31, 2008, all options were exercisable and had a weighted average life of 3.78 years with an aggregate intrinsic value of $8.7 million.

Effective January 1, 2006, the Company adopted SFAS 123(R), using the modified-prospective transition method. The adoption did not have a material effect on the Company s consolidated financial position or results of operations. In connection with the filing of a registration statement with the Securities and Exchange Commission on March 7, 2006, for the public offering of common stock, the Company became a public entity for purposes of SFAS 123(R). For public entities, stock option liability awards are required to be valued using the Black-Scholes or similar option valuation model. In connection therewith, the Company changed from the intrinsic value method to the fair value method of accounting for its stock options and restricted stock. In determining the fair value of the vested stock options and compensation expense as of and for the years ended December 31, 2007 and 2006, the Company utilized the Black-Sholes option pricing value model based on a fair value for stock option grants of $11.96 per share, weighted average expected life of 2.38 years, expected volatility of 38%, weighted average risk-free interest rate of 4.75% and a dividend yield of zero. The expected life is based on management s expectations of option exercises. The volatility is based on the average volatility of our peer group for a period approximating the expected life of the options. The risk-free interest rate is based on treasury rates in effect at December 31, 2006 commensurate with the expected life of the stock options.

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Notes to Consolidated Financial Statements (continued)

The following table summarizes information about stock options outstanding at December 31, 2008:

	Options Outstanding			Options Exercisable	
Exercise Prices	**Number Outstanding**	**Weighted Average Remaining Contractual Life**	**Weighted Average Exercise Price**	**Number Exercisable**	**Weighted-Average Exercise Price**
$0.71	131,440	3.25 years	$ 0.71	131,440	$ 0.71
1.27	301,250	1.75 years	1.27	301,250	1.27
5.71	17,510	6.33 years	5.71	17,510	5.71
	450,200		1.28	450,200	1.28

Restricted Stock

On October 3, 2005, the Company adopted the 2005 Plan and reserved a maximum of 5,500,000 shares of common stock that may be issued pursuant to the 2005 Plan. As of December 31, 2008, the Company had 3,593,442 shares of restricted stock available to grant to directors, officers and key employees under the 2005 Plan. All grants were made on or after October 3, 2005. Restricted stock is awarded in the name of the recipient and except for the right of disposal, constitutes issued and outstanding shares of the Company s common stock for all corporate purposes during the period of restriction including the right to receive dividends, subject to forfeiture. Restricted stock grants vest over periods ranging from one to three years.

The Company issued 990,517 shares of restricted stock during 2005. A summary of changes in the non-vested restricted shares for the period of December 31, 2005 to December 31, 2008, is presented below:

	Number of non-vested shares	**Weighted average grant-date fair value**
Non-vested restricted shares at December 31, 2005	990,517	$ 13.40
Granted	200,772	13.27
Vested	(304,733)	13.40
Forfeited	(105,149)	13.45
Non-vested restricted shares at December 31, 2006	781,407	$ 13.36
Granted	629,684	22.12
Vested	(321,750)	13.27
Forfeited	(41,635)	14.15
Non-vested restricted shares at December 31, 2007	1,047,706	$ 18.36
Granted	461,120	28.93
Vested	(369,091)	13.93
Forfeited	(28,843)	25.05
Non-vested restricted shares at December 31, 2008	1,110,892	$ 24.05

The fair value of the restricted shares that vested during 2008 at their vesting date was $11.1 million. As of December 31, 2008, there was $17.1 million of unrecognized compensation expense related to non-vested restricted shares. The expense is expected to be recognized over a weighted average period of 1.7 years.

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Notes to Consolidated Financial Statements (continued)

14. Oil and Gas Property Information

The following table sets forth the Company s results of operations from oil and natural gas producing activities for the years ended December 31, 2008, 2007 and 2006 (in thousands):

	Year Ended December 31,		
	2008	2007	2006
Oil and natural gas sales	$ 939,906	$ 606,514	$ 468,602
Production expense and tax	(160,245)	(109,051)	(85,196)
Exploration expense	(40,160)	(9,163)	(19,738)
Depreciation, depletion, amortization and accretion	(146,208)	(91,678)	(63,810)
Property impairments	(28,847)	(17,879)	(11,751)
Income taxes	(214,489)	(102,676)	
Results from oil and natural gas producing activities	$ 349,957	$ 276,067	$ 288,107
(The below information is unaudited)			
Pro forma presentation for income tax:			
Results from oil and natural gas producing activities before pro forma income tax		$ 378,743	$ 288,107
Pro forma income tax		(143,922)	(109,481)
Results from pro forma oil and natural gas producing activities		$ 234,821	$ 178,626

Prior to the completion of the Company s initial public offering, the Company was a subchapter S corporation and its taxes were payable by its shareholders. The table above shows taxes from May 14, 2007 to the end of the year at statutory rates and pro forma for the remaining periods.

Costs incurred in oil and gas activities

Costs incurred, both capitalized and expensed, in connection with the Company s oil and gas acquisition, exploration and development activities for the three years ended December 31, 2008, 2007 and 2006 are shown below (in thousands).

	Year Ended December 31,		
	2008	2007	2006
Property Acquisition Costs:			
Proved	$ 74,663	$ 4,166	$ 6,564
Unproved	199,621	21,729	29,970
Total property acquisition costs	274,284	25,895	36,534
Exploration Costs	235,263	181,883	68,686
Development Costs	471,820	316,741	221,286
Total	$ 981,367	$ 524,519	$ 326,506

Exploration costs above include asset retirement costs of $687,000, $236,000 and $214,000 and development costs above include asset retirement costs of $3,252,000, $401,000 and $6,658,000 for the years 2008, 2007 and 2006, respectively.

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Notes to Consolidated Financial Statements (continued)

Aggregate capitalized costs

Aggregate capitalized costs relating to the Company s oil and gas producing activities, and related accumulated depreciation, depletion and amortization as of December 31, 2008 and 2007 are as follows (in thousands):

	December 31, 2008	December 31, 2007
Proved oil and gas properties	$ 2,250,757	$ 1,518,981
Unproved oil and gas properties	248,689	65,830
Total	2,499,446	1,584,811
Less-accumulated depreciation, depletion and amortization	(589,513)	(440,700)
Net capitalized costs	$ 1,909,933	$ 1,144,111

Under the successful efforts method of accounting, the costs of drilling an exploratory well are capitalized pending determination of whether proved reserves can be attributed to the discovery. When initial drilling operations are complete, management determines whether the well has discovered oil and gas reserves and, if so, whether those reserves can be classified as proved. Often, the determination of whether proved reserves can be recorded under Securities and Exchange Commission (SEC) guidelines cannot be made when drilling is completed. In those situations where management believes that commercial hydrocarbons have not been discovered, the exploratory drilling costs are reflected in the Consolidated Statement of Income as dry hole costs (a component of exploration expense). Where sufficient hydrocarbons have been discovered to justify further exploration or appraisal activities, exploratory drilling costs are deferred on the Consolidated Balance Sheet pending the outcome of those activities.

Operating and financial management review quarterly the status of all deferred exploratory drilling costs in light of ongoing exploration activities in particular, whether the Company is making sufficient progress in its ongoing exploration and appraisal efforts. If management determines that future appraisal drilling or development activities are not likely to occur, any associated exploratory well costs are expensed in that period.

The following table presents the amount of capitalized exploratory drilling costs pending evaluation at December 31 for each of the last three years and changes in those amounts during the years then ended (in thousands):

	2008	2007	2006
Balance, January 1,	$ 32,936	$ 10,049	$ 1,874
Additions to capitalized exploratory well costs pending determination of proved reserves	151,301	139,765	65,721
Reclassification to proved oil and natural gas properties based on the determination of proved reserves	(117,958)	(113,329)	(44,203)
Capitalized exploratory well costs charged to expense	(20,005)	(3,549)	(13,343)
Balance, December 31,	$ 46,274	$ 32,936	$ 10,049
Number of projects at year-end	56	45	26

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Notes to Consolidated Financial Statements (continued)

15. Supplemental Oil and Gas Information (Unaudited)

The following table shows estimates of proved reserves prepared by the Company s technical staff and independent external reserve engineers in accordance with SEC definitions. Ryder Scott Company, L. P. prepared reserve estimates for properties comprising approximately 83% of the Company s standardized measure of discounted future net cash flows as of December 31, 2008, 2007 and 2006. Remaining reserve estimates were prepared by the Company s technical staff. All reserves stated here are located in the United States of America.

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

There are numerous uncertainties inherent in estimating quantities of proved oil and natural gas reserves. Oil and natural gas reserve engineering is a subjective process of estimating underground accumulations of oil and natural gas that cannot be precisely measured, and estimates of engineers other than the Company s might differ materially from the estimates set forth herein. The accuracy of any reserve estimate is a function of the quality of available data and of engineering and geological interpretation and judgment. Results of drilling, testing and production subsequent to the date of the estimate may justify revision of such estimate. Accordingly, reserve estimates are often different from the quantities of oil and gas that are ultimately recovered.

Gas imbalance receivables and liabilities for each of the three years ended December 31, 2008, 2007 and 2006, were not material and have not been included in the reserve estimates.

Proved oil and gas reserves

	Natural Gas (MMcf)	**Crude Oil (MBbls)**
Proved reserves as of December 31, 2005	108,118	98,645
Revisions of previous estimates	(307)	416
Extensions, discoveries and other additions	23,235	6,111
Production	(9,225)	(7,480)
Sale of minerals in place		
Purchase of minerals in place	44	346
Proved reserves as of December 31, 2006	121,865	98,038
Revisions of previous estimates	7,434	2,134
Extensions, discoveries and other additions	64,988	12,845
Production	(11,534)	(8,699)
Sale of minerals in place		(228)
Purchase of minerals in place	66	55
Proved reserves as of December 31, 2007	182,819	104,145
Revisions of previous estimates	(16,179)	(10,527)
Extensions, discoveries and other additions	167,288	19,765
Production	(17,151)	(9,147)
Sale of minerals in place		
Purchase of minerals in place	1,361	2,003
Proved reserves as of December 31, 2008	318,138	106,239

The increases in oil and natural gas reserve volumes attributable to extensions, discoveries and other additions are a result of the Company s exploration and development activity.

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Continental Resources, Inc. and Subsidiary

Notes to Consolidated Financial Statements (continued)

The following reserve information sets forth the estimated quantities of proved developed and proved undeveloped oil and natural gas reserves of the Company as of December 31, 2006, 2007 and 2008:

	December 31,	Natural Gas (MMcf)	Crude Oil (MBbls)	Oil Equivalent (MBoe)
Proved Developed Reserves	2006	70,420	75,336	87,073
	2007	128,831	79,756	101,228
	2008	153,536	80,387	105,976
Proved Undeveloped Reserves	2006	51,445	22,702	31,276
	2007	53,988	24,389	33,387
	2008	164,602	25,852	53,286

Proved developed reserves are proved reserves expected to be recovered through existing wells with existing equipment and operating methods. Proved undeveloped reserves are proved reserves that require incremental capital expenditures to recover. Natural gas is converted to barrels of oil equivalent using a conversion factor of six thousand cubic feet per barrel.

Standardized measure of discounted future net cash flows relating to proved oil and gas reserves

The standardized measure of discounted future net cash flows presented in the following table was computed using year-end prices and costs and a 10% discount factor. However, the Company cautions that actual future net cash flows may vary considerably from these estimates. Although the Company s estimates of total proved reserves, development costs and production rates were based on the best available information, the development and production of the oil and gas reserves may not occur in the periods assumed. Actual prices realized, costs incurred and production quantities may vary significantly from those used. Therefore, such estimated future net cash flows computations should not be considered to represent the Company s estimate of the expected revenues or the current value of existing proved reserves.

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Continental Resources, Inc. and Subsidiary

Notes to Consolidated Financial Statements (continued)

Prior to the completion of the Company s initial public offering on May 14, 2007, the Company was a subchapter S corporation where taxes were paid by its shareholders. In connection with the completion of its initial public offering, the Company converted to a subchapter C corporation, a taxable entity. As such we are showing taxes in our standardized measure as of December 31, 2008 and 2007, but not for prior years. Taxes as of December 31, 2006 are shown in the pro forma presentation.

	December 31,		
	2008	2007	2006
	(In thousands)		
Historical:			
Future cash inflows	$ 5,777,441	$ 9,754,787	$ 5,244,078
Future production costs	(1,993,888)	(2,427,862)	(1,763,573)
Future development and abandonment costs	(663,497)	(461,811)	(466,057)
Future income taxes	(703,329)	(2,008,293)	
Future net cash flows	2,416,727	4,856,821	3,014,448
10% annual discount for estimated timing of cash flows	(1,139,626)	(2,274,482)	(1,429,976)
Standardized measure of discounted future net cash flows	$ 1,277,101	$ 2,582,339	$ 1,584,472
Pro forma for income tax:			
Future cash inflows			$ 5,244,078
Future production costs			(1,763,573)
Future development and abandonment costs			(466,057)
Future income taxes			(1,061,163)
Future net cash flows pro forma for income taxes			1,953,285
10% annual discount for estimated timing of cash flows			(926,588)
Standardized measure of discounted future net cash flows			$ 1,026,697

The year-end weighted average oil price utilized in the computation of future cash inflows was $39.69, $82.86, and $47.85 per barrel at December 31, 2008, 2007 and 2006, respectively. The year-end weighted average natural gas price utilized in the computation of future cash inflows was $4.90, $6.16, and $4.54 per Mcf at December 31, 2008, 2007 and 2006, respectively. Future cash flows are reduced by estimated future costs to develop and to produce the proved reserves, as well as certain abandonment costs, based on year-end cost estimates assuming continuation of existing economic conditions.

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Continental Resources, Inc. and Subsidiary

Notes to Consolidated Financial Statements (continued)

The changes in the aggregate standardized measure of discounted future net cash flows attributable to the Company s proved oil and gas reserves are presented below for each of the past three years (in thousands):

	December 31,		
	2008	2007	2006
Standardized measure of discounted future net cash flows at the beginning of the year	$ 2,582,339	$ 1,584,472	$ 2,204,375
Extensions, discoveries and improved recovery, less related costs	276,774	643,016	138,119
Revisions of previous quantity estimates	(169,605)	90,188	5,455
Changes in estimated future development and abandonment costs	(55,793)	(14,597)	(139,623)
Net purchase (sale) of minerals in place	115,711	2,050	5,953
Net change in prices and production costs	(1,981,977)	1,313,657	(520,756)
Accretion of discount	258,234	158,447	220,438
Sales of oil and natural gas produced, net of production costs	(779,661)	(497,463)	(383,405)
Development costs incurred during the period	305,028	232,356	123,971
Change in timing of estimated future production and other	26,732	15,677	(70,055)
Change in income taxes	699,319		