CONTINENTAL RESOURCES INC
Form 10-K
February 26, 2010
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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, 2009

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 whether the registrant has submitted electronically and posted on its corporate Web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T (§232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files). Yes ¨ 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, 2009 aggregate market value was $1,255,456,426.

As of February 19, 2010, the registrant had 169,957,157 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 in 2010, which will be filed with the Commission no later than within 120 days after the end of the fiscal year, are incorporated by reference into Part III of this Form 10-K.

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Glossary of Crude 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 crude oil converted to six thousand cubic feet of natural gas.

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

ECO-Pad ™. A Continental Resources Inc. trademark which describes a well site layout approved by the North Dakota Industrial Commission which allows for drilling four wells from a single pad resulting in less environmental impact and lower drilling and completion costs.

Enhanced recovery. The recovery of crude 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 a new field or to find a new reservoir in a field previously found to be productive of crude oil or natural gas in another 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 crude oil or natural gas does not have to travel as far through the formation.

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

Mcf. One thousand cubic feet of natural gas.

Mcfe. One thousand cubic feet of natural gas equivalent, with one barrel of crude oil being equivalent to six Mcf.

MBoe. One thousand Boe.

MMBoe. One million Boe.

MMBtu. One million British thermal units.

MMcf. One million cubic feet of natural gas.

MMMBtu. One billion British thermal units.

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 crude 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 Securities and Exchange Commission (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 crude oil and natural 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. These quantities of crude oil and natural gas which by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be economically producible from a given date

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forward, from known reservoirs and under existing economic conditions, operating methods, and government regulations prior to the time at which contracts providing the right to operate expire, unless evidence indicates that renewal is reasonably certain.

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 crude 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.

Standardized Measure. Discounted future net cash flows estimated by applying the 12-month unweighted arithmetic average of the first-day-of-the-month price for the period January 2009 to December 2009 (for year-end 2009) or year-end prices (for 2008 and prior) 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 crude oil and natural 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 a crude oil reservoir to push additional crude 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 crude oil or natural 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 crude oil, natural 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 simila 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 crude oil and natural gas properties and that there will be no material acquisitions, divestitures or financings except as otherwise described.

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Forward-looking statements may include statements about our:

- business strategy;
- reserves (including uncertainties about the effect of the SEC s new rules regarding reserve reporting);
- technology;
- financial strategy;
- crude oil and natural gas realized prices;
- timing and amount of future production of crude oil and natural gas;
- the amount, nature and timing of capital expenditures;
- drilling of wells;
- competition and government regulations;
- marketing of crude oil and natural gas;
- exploitation or property acquisitions;
- 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.

For the year ended December 31, 2009, we changed our reporting regions from Rockies, Mid-Continent and Gulf Coast to North, South and East. The primary effect of this change was to combine the Mid-Continent and Gulf Coast regions into the South region and to split the East region from the new South region. The North region is north of Kansas and west of the Mississippi river and includes the Red River units, Montana Bakken, North Dakota Bakken and other Rockies. The South region includes Kansas and all our properties south of there and west of the Mississippi river including Arkoma and Anadarko Woodford. The East region contains our properties east of the Mississippi river including the Illinois Basin and Michigan.

Item 1. Business

General

We are an independent crude oil and natural gas exploration and production company with operations in the North, South and East regions of the United States. We were originally formed in 1967 to explore, develop and produce crude oil and natural gas properties. Through 1993, our activities and growth remained focused primarily in Oklahoma. In 1993, we expanded our activity into the North region. Approximately 76% of our estimated proved reserves as of December 31, 2009 are located in the North 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 crude oil and natural gas reserves from unconventional formations. As a result of these efforts, we have grown substantially through the drill bit, adding 224.2 MMBoe of proved crude oil and natural gas reserves through extensions and discoveries from January 1, 2005 through December 31, 2009 compared to 2.8 MMBoe added through proved reserve purchases during that same period.

As of December 31, 2009, our estimated proved reserves were 257.3 MMBoe, with estimated proved developed reserves of 113.6 MMBoe, or 44% of our total estimated proved reserves. Crude oil comprised 67% of our total estimated proved reserves. For the year ended December 31, 2009, we generated revenues of $626.2 million and operating cash flows of $375.9 million. For the year and quarter ended December 31, 2009, daily production averaged 37,324 and 37,747 Boe per day, respectively. This represents growth of 14% and 5% as compared to the year and quarter ended December 31, 2008, when daily production averaged 32,803 Boe and 36,018 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, 2009, average daily production for the three months ended December 31, 2009 and the reserve-to-production index in our principal regions. Our reserve estimates as of December 31, 2009 are based primarily on a reserve report prepared by our independent reserve engineers, Ryder Scott Company, L.P (Ryder Scott). In preparing its report, Ryder Scott evaluated properties representing approximately 90% of our PV-10. Our technical staff evaluated properties representing the remaining 10% of our PV-10. Our estimated proved reserves and related future net revenues, PV-10 and Standardized Measure at December 31, 2009 were determined using the 12-month unweighted arithmetic average of the first-day-of-the-month price for the period January 2009 through December 2009, without giving effect to derivative transactions, and were held constant throughout the life of the properties. These prices were $61.18 per Bbl for oil and oil equivalents and $3.87 per Mcf for gas ($52.76 per Bbl for oil and $3.67 per Mcf for gas net of location differentials).

	At December 31, 2009				Average daily production fourth quarter 2009 (Boe per day)	Percent of Total	Annualized reserve/ production index [2]
	Proved reserves (MBoe)	Percent of total	PV-10 [1] (in thousands)	Net producing wells			
North:							
Red River units							
Cedar Hills Unit	39,797	15.4%	$ 758,936	130	11,243	29.8%	9.7
Other	13,566	5.3%	180,997	102	3,006	7.9%	12.4
Bakken field							
Montana Bakken	28,773	11.2%	342,268	103	5,047	13.4%	15.6
North Dakota Bakken	105,518	41.0%	665,268	78	7,843	20.8%	36.9
Other	8,502	3.3%	99,314	262	1,993	5.3%	11.7
South:							
Oklahoma Woodford							
Anadarko Woodford	3,859	1.5%	14,177	5	740	2.0%	14.3
Arkoma Woodford	44,571	17.3%	45,928	47	3,573	9.5%	34.2
Other	8,690	3.4%	62,349	291	2,831	7.4%	8.4
East	4,017	1.6%	76,703	459	1,471	3.9%	7.5
Total	257,293	100.0%	$ 2,245,940	1,477	37,747	100.0%	18.7

(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, 2009 is $1.8 billion, a $0.4 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 crude oil and natural 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 2009 production into the proved reserve quantity at December 31, 2009.

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The following table provides additional information regarding our key development areas as of December 31, 2009 and budgeted for 2010:

	Developed acres		Undeveloped acres		2010	
	Gross	Net	Gross	Net	Gross wells planned for drilling	Capital expenditures (in millions)(1)
North:						
Red River units	149,994	132,247			16	$ 70
Bakken field						
Montana Bakken	84,300	66,135	128,868	97,364	14	43
North Dakota Bakken	215,849	93,953	996,524	387,895	218	491
Other	60,961	46,537	302,353	176,879	5	8
South:						
Oklahoma Woodford						
Anadarko Woodford	49,900	28,648	194,892	119,872	15	39
Arkoma Woodford	96,073	20,890	60,233	23,894	58	57
Southern Oklahoma Woodford			28,789	5,247		
Other	100,404	48,576	264,135	121,421	8	25
East	30,149	29,292	189,978	161,733	14	5
Total	787,630	466,278	2,165,772	1,094,305	348	$ 738

(1) Capital expenditures budgeted for 2010 include amounts for drilling, capital workovers and facilities and exclude amounts for land of $92 million, seismic of $9 million, and $11 million for vehicles, computers and other equipment. While the above capital expenditures budget reflects our current intentions, we expect our cash flows from operations and the availability under our revolving credit facility will be sufficient to meet our capital expenditure needs. A decline in crude 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 Crude 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, 2009, crude oil comprises 67% of our total proved reserves and 74% of our 2009 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, 2005 through December 31, 2009, proved crude oil and natural gas reserve additions through extensions and discoveries were 224.2 MMBoe compared to 2.8 MMBoe of proved reserve purchases.

Internally Generate Prospects. Although we evaluate strategic acquisitions periodically, 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 later entrants into a developing play.

3

Focus on Unconventional Crude Oil and Natural Gas Resource Plays. Our experience with horizontal drilling, advanced fracture stimulation and enhanced recovery technologies allows us to commercially develop unconventional crude oil and natural gas resource reservoirs, such as the Red River B dolomite, Bakken shale and Oklahoma Woodford shale formations. Production rates in the Red River units also have been increased through the use of enhanced recovery technology. Our production from the Red River units, the Bakken field, and the Oklahoma Woodford shale comprised approximately 11,259 MBoe, or 83% of our total crude oil and natural gas production during the year ended December 31, 2009.

Acquire Significant Acreage Positions in New or Developing Plays. In addition to the 635,100 net undeveloped acres held in the Montana and North Dakota Bakken shale and Oklahoma Woodford shale fields, we held 223,000 net undeveloped acres in other crude oil and natural gas shale plays as of December 31, 2009. Our technical staff is focused on identifying and testing new unconventional crude 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 1,094,300 net undeveloped and 466,300 net developed acres as of December 31, 2009. 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 Oklahoma, the Haynesville shale in Louisiana, the Lewis shale in Wyoming, the Barnett and Woodford shales in the Marfa Basin, 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, Lodgepole of 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 700 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 8 high pressure air injection (HPAI) floods.

Control Operations Over a Substantial Portion of Our Assets and Investments. As of December 31, 2009, we operated properties comprising 93% 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 crude oil and natural gas industry. Our Chief Executive Officer, Harold G. Hamm, began his career in the crude oil and natural gas industry in 1967. Our 8 senior officers have an average of 29 years of crude oil and natural gas industry experience. Additionally, our technical staff, which includes 34 petroleum engineers, 20 geoscientists and 11 landmen, has an average of 17 years experience in the industry.

Strong Financial Position. As of February 19, 2010, we had outstanding borrowings under our revolving credit facility of approximately $198.0 million and available borrowing capacity of $551.2 million under our selected commitment level. We have elected to set the commitment level at $750.0 million, which is equal to the revolving credit facility note amount of $750.0 million and the established borrowing base is $1.0 billion. 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 2010 capital expenditures budget has been established based on our current expectation of available cash flows from operations and availability under our

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revolving credit facility. Should expected available cash flows 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 flows from operations. We anticipate that we will negotiate a new revolving credit facility during the second quarter of 2010 as our current revolving credit facility matures in April 2011.

Crude Oil and Natural Gas Operations

In December 2008, the SEC adopted new rules related to modernizing reserve calculation and disclosure requirements for oil and natural gas companies that became effective prospectively for annual reporting periods ending on or after December 31, 2009. The new rules expand the definition of oil and gas producing activities to include the extraction of saleable hydrocarbons from oil sands, shale, coal beds or other nonrenewable natural resources that are intended to be upgraded into synthetic oil or gas, and activities undertaken with a view to such extraction. The use of new technologies is now permitted in the determination of proved reserves if those technologies have been demonstrated empirically to lead to reliable conclusions about reserve volumes. Other definitions and terms were revised, including the definition of proved reserves, which was revised to indicate that entities must use the unweighted average of first-day-of-the-month commodity prices over the preceding 12-month period, rather than the year-end price, when estimating whether reserve quantities are economical to produce. Likewise, the 12-month average price is now used to calculate reserves used in computing depreciation, depletion and amortization. Another significant provision of the new rules is a general requirement that, subject to limited exceptions, proved undeveloped reserves may only be booked if they relate to wells scheduled to be drilled within five years of the date of booking.

The initial application of new rules related to modernizing reserve calculation and disclosure requirements resulted in a upward adjustment to our total proved reserves as of December 31, 2009 primarily as a result of the amendments to the definition of oil and gas reserves and higher oil prices. See *Notes to Consolidated Financial Statements Note 15. Supplemental Crude Oil and Natural Gas Information (Unaudited).*

Proved Reserves

The following tables set forth our estimated proved crude oil and natural gas reserves, percent of total proved reserves that are proved developed and the PV-10 as of December 31, 2009 by reserve category and region. The total standardized measure of discounted cash flows as of December 31, 2009 is also presented. Ryder Scott, our independent petroleum engineers, evaluated properties representing approximately 90% of our PV-10, and our technical staff evaluated the remaining properties. A copy of Ryder Scott s summary report is included as an exhibit to this Annual Report on Form 10-K. Our estimated proved reserves and related future net revenues and PV-10 at December 31, 2009 were determined using the 12-month unweighted arithmetic average of the first-day-of-the-month price for the period January 2009 through December 2009, without giving effect to derivative transactions, and were held constant throughout the life of the properties. These prices were $61.18 per Bbl for crude oil and oil equivalents and $3.87 per Mcf for natural gas ($52.76 per Bbl for crude oil and $3.67 per Mcf for natural gas net of location differentials).

	December 31, 2009			
	Crude Oil (MBbls)	**Natural Gas (MMcf)**	**Total (MBoe)**	**PV-10 [1] (in thousands)**
Proved developed producing	83,745	169,556	112,004	$ 1,797,923
Proved developed non-producing	1,525	226	1,563	10,689
Proved undeveloped	88,010	334,298	143,726	437,328
Total proved reserves	173,280	504,080	257,293	$ 2,245,940
Standardized measure				$ 1,841,540

(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

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revenues. The Standardized Measure at December 31, 2009 is $1.8 billion, a $0.4 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 crude oil and natural 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.

	Proved Developed			Proved Undeveloped		
	Crude Oil (MBbls)	Natural Gas (MMcf)	Total (MBoe)	Crude Oil (MBbls)	Natural Gas (MMcf)	Total (MBoe)
North:						
Red River units						
Cedar Hills	32,518	23,290	36,400	3,397		3,397
Other	11,485	243	11,526	2,008	194	2,040
Bakken field						
Montana Bakken	15,203	17,353	18,095	9,169	9,056	10,678
North Dakota Bakken	14,305	19,465	17,549	72,241	94,366	87,969
Other	6,910	6,222	7,947	554		554
South:						
Oklahoma Woodford						
Anadarko Woodford	97	7,657	1,373	52	14,607	2,487
Arkoma Woodford	38	57,790	9,670	49	209,113	34,901
Other	1,226	36,482	7,306	223	6,962	1,383
East	3,488	1,280	3,701	317		317
Total	85,270	169,782	113,567	88,010	334,298	143,726

We have historically added reserves through our exploration program and development activities. See *Items 1. Business* and *Item 2. Properties*. Changes in proved reserves were as follows:

MBoe	Year Ended December 31, 2009	2008	2007
Proved reserves beginning of year	159,262	134,615	118,349
Revisions of previous estimates	1,195	(13,224)	3,373
Extension, discoveries and other additions	110,454	47,647	23,676
Production	(13,623)	(12,006)	(10,621)
Sales of minerals in place			(228)
Purchase of minerals in place	5	2,230	66
Proved reserves end of year	257,293	159,262	134,615

Revisions. Revisions represent changes in previous reserves estimates, either upward or downward, resulting from new information normally obtained from development drilling and production history or resulting from a change in economic factors, such as commodity prices, operating costs, or development costs. December 31, 2008 revisions were primarily due to lower commodity prices at the end of 2008.

Reserves at December 31, 2009 were computed using the 12-month unweighted average of the first-day-of-the-month prices as required by the new SEC rules. However, had we been able to use December 31, 2009 prices as in previous years, our revisions for 2009 would have increased by an additional 4,070 MBoe.

Extensions, discoveries and other additions. These are additions to proved reserves that result from (1) extension of the proved acreage of previously discovered reservoirs through additional drilling in periods subsequent to discovery and (2) discovery of new fields with proved reserves or of new reservoirs of proved reserves in old fields. Extensions, discoveries and other additions at December 31, 2009 include increases in

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proved undeveloped locations as a result of the change in the SEC s rules to allow producers in continuous accumulation plays to report additional undrilled locations beyond one offset on each side of a horizontal producing well.

We expect that a significant portion of future reserve additions will come from our major development projects including North Dakota Bakken, Arkoma Woodford and Anadarko Woodford. We may also purchase proved properties in strategic acquisitions.

Qualifications of Technical Persons and Internal Controls Over Reserves Estimation Process. Ryder Scott, our independent petroleum consultant estimated, in accordance with generally accepted petroleum engineering and evaluation principles and definitions and guidelines established by the SEC, 90% of our proved reserve information as of December 31, 2009 included in this Annual Report on Form 10-K. The technical persons responsible for preparing the reserves estimates presented herein meet the requirements regarding qualifications, independence, objectivity and confidentiality set forth in the Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserves Information promulgated by the Society of Petroleum Engineers.

We maintain an internal staff of petroleum engineers and geoscience professionals who work closely with our independent petroleum consultant to ensure the integrity, accuracy and timeliness of data furnished to Ryder Scott in their reserves estimation process. In the fourth quarter, our technical team meets regularly with representatives of Ryder Scott to review properties and discuss methods and assumptions used in Ryder Scott s preparation of the year-end reserves estimates. While we have no formal committee specifically designated to review reserves reporting and the reserves estimation process, a copy of the Ryder Scott reserve report is reviewed by our audit committee with representatives of Ryder Scott and our internal technical staff before dissemination of the information. Additionally, our senior management reviews and approves the Ryder Scott reserve report and any internally estimated significant changes to our proved reserves on a quarterly basis.

Our Senior Vice President Resource Development is the technical person primarily responsible for overseeing the preparation of our reserves estimates. Our Senior Vice President Resource Development has a Bachelor of Science degree in Mechanical Engineering and 35 years of industry experience with positions of increasing responsibility in operations, acquisitions, engineering and evaluations. He has worked in the area of reserves and reservoir engineering most of his career and is a member of the Society of Petroleum Engineers. The Senior Vice President Resource Development reports directly to our President and Chief Operating Officer. These reserves estimates are reviewed and approved by senior engineering staff with final approval by the Chief Operating Officer and certain members of senior management.

Proved reserves are those quantities of oil and natural gas, which, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be economically producible from a given date forward, from known reservoirs, and under existing economic conditions, operating methods, and government regulations. The term reasonable certainty implies a high degree of confidence that the quantities of oil and/or natural gas actually recovered will equal or exceed the estimate. To achieve reasonable certainty, Ryder Scott employed technologies that have been demonstrated to yield results with consistency and repeatability. The technologies and economic data used in the estimation of our proved reserves include, but are not limited to, well logs, geologic maps and available downhole and production data, seismic data and well test data.

Proved Undeveloped Reserves. Our proved undeveloped reserves at December 31, 2009 were 143,726 MBoe, consisting of 88,010 MBbls of crude oil and 334,298 MMcf of natural gas. In 2009, we developed approximately 9% of our total proved undeveloped reserves booked as of December 31, 2008 through the drilling of 64 gross (16.1 net) development wells at an aggregate capital cost of approximately $91.9 million. Estimated future development costs relating to the development of PUDs are projected to be approximately $360 million in 2010, $570 million in 2011, and $540 million in 2012.

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Developed and Undeveloped Acreage

The following table presents the total gross and net developed and undeveloped acreage by region as of December 31, 2009:

	Developed acres		Undeveloped acres		Total	
	Gross	Net	Gross	Net	Gross	Net
North:						
Red River units	149,994	132,247			149,994	132,247
Bakken field						
Montana Bakken	84,300	66,135	128,868	97,364	213,168	163,499
North Dakota Bakken	215,849	93,953	996,524	387,895	1,212,373	481,848
Other	60,961	46,537	302,353	176,879	363,314	223,416
South:						
Oklahoma Woodford						
Anadarko Woodford	49,900	28,648	194,892	119,872	244,792	148,520
Arkoma Woodford	96,073	20,890	60,233	23,894	156,306	44,784
Southern Oklahoma Woodford			28,789	5,247	28,789	5,247
Other	100,404	48,576	264,135	121,421	364,539	169,997
East	30,149	29,292	189,978	161,733	220,127	191,025
Total	787,630	466,278	2,165,772	1,094,305	2,953,402	1,560,583

The following table sets forth the number of gross and net undeveloped acres as of December 31, 2009 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:

	2010		2011		2012	
	Gross	Net	Gross	Net	Gross	Net
North:						
Red River units						
Bakken field						
Montana Bakken	24,757	19,258	61,852	50,437	17,835	14,810
North Dakota Bakken	97,355	41,796	227,402	80,810	281,156	102,341
Other	37,621	19,473	72,064	46,967	41,490	24,168
South:						
Oklahoma Woodford						
Anadarko Woodford	12,938	7,714	123,932	78,743	44,851	23,871
Arkoma Woodford	20,492	7,867	16,198	7,187	12,455	7,818
Southern Oklahoma Woodford	4,317	652	18,355	3,008	5,987	1,561
Other	131,365	62,018	60,657	47,114	47,918	7,488
East	34,863	26,585	44,781	36,809	61,554	56,272
Total	363,708	185,363	625,241	351,075	513,246	238,329

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Drilling Activity

During the three years ended December 31, 2009, we drilled exploratory and development wells as set forth in the table below:

	2009		2008		2007	
	Gross	Net	Gross	Net	Gross	Net
Exploratory wells:						
Oil	14	6.5	41	18.2	33	15.6
Natural gas	34	9.0	73	19.5	79	13.1
Dry	16	9.0	12	8.9	4	2.5
Total exploratory wells	64	24.5	126	46.6	116	31.2
Development wells:						
Oil	106	39.1	153	89.3	92	69.5
Natural gas	45	4.1	72	13.4	49	10.3
Dry	2	0.1	8	3.2	5	1.1
Total development wells	153	43.3	233	105.9	146	80.9
Total wells	217	67.8	359	152.5	262	112.1

As of December 31, 2009, there were 70 gross (23.1 net) wells in the process of drilling, completing or waiting on completion.

As of February 19, 2010, we operated 14 rigs on our properties. Our rig activity during 2010 will be dependent on crude 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 *Item 1A. 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 Crude 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 believe our cash flows from operations and borrowings available under our revolving credit facility will be sufficient to satisfy our 2010 capital budget. A decline in crude 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.

North Region

Our properties in the North region represented 93% of our PV-10 as of December 31, 2009. During the three months ended December 31, 2009, our average daily production from such properties was 25,938 net Bbls of crude oil and 19,160 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 46% of our PV-10 in the North region as of December 31, 2009 and 49% of our average daily North region Boe production for the three months ended December 31, 2009. The 8 units comprising the Red River units are located along the Cedar Creek Anticline in North Dakota, South Dakota and Montana and produce crude 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

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by the Energy Information Administration in 2008 as the 7th largest onshore, lower 48 field in the United States ranked by liquid proved reserves.

In the Red River units, we plan to complete pattern drilling on the waterflood project in the Cedar Hills units and resume development activity in the Medicine Pole Hills and Buffalo units in 2010. We have allocated $70 million, or 9%, of our operational capital expenditure budget to the Red River units, which will support 1 operated rig and a significant investment in facilities and infrastructure. Production in the units is expected to peak mid-year 2010 in a range of 15,000 Boe per day to 15,500 Boe per day and then level off through the remainder of 2010.

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, 2009, we had drilled 226 horizontal wells within this 49,700-acre unit, with 111 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, 2009, this 7,800-acre unit contained 11 horizontal producing wells and 6 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 crude 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 11,539 net Boe per day in December 2009 from 2,185 net Boe per day in November 2003. As of December 31, 2009, the average density in the Cedar Hill units was approximately 1 producing wellbore per 420 acres. We currently plan to drill 12 new horizontal wellbores and 1 horizontal extension of existing wellbores in the Cedar Hills units during 2010, 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 2010, we plan to invest approximately $46.6 million drilling and improving facilities in the Cedar Hills units.

Medicine Pole Hills Units. The Medicine Pole Hills units (MPHU) are approximately five miles east of the southern portion of the CHNU. We acquired the Medicine Pole Hills unit in 1995. At that time, the 9,600- acre unit consisted of 18 vertical producing wellbores and 4 injection wellbores under HPAI producing 525 net Bbls of crude 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 1,357 net Bbls of crude oil and 1,234 Mcf of natural gas per day during December 2009. In 2010, we plan to invest approximately $6.9 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 crude 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 2009, 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 2009 was 1,377 net Bbls of crude oil per day compared to an average of 1,162 net Bbls of crude oil per day for the first half of 2005. In 2010, we plan to invest $16.7 million for drilling, capital workovers and facilities in the Buffalo Red River units.

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Bakken Field

We control one of the largest acreage positions in the Bakken field of Montana and North Dakota with approximately 1,425,500 gross (645,300 net) acres as of December 31, 2009. Approximately 25% of the net acreage is developed and 75% of the net acreage is undeveloped as of December 31, 2009. Our properties within the Bakken field in Montana and North Dakota represented 49% of our PV-10 in the North region as of December 31, 2009 and 44% of our average daily North region Boe production for the three months ended December 31, 2009. As of December 31, 2009 we had completed 413 gross (183.3 net) wells in the Bakken field.

The Bakken field produces from the Bakken shale which is estimated to contain up to 4.3 billion barrels of recoverable crude oil according to a report issued by the United State Geological Survey (USGS) in April 2008, making it the largest continuous crude oil accumulation ever assessed by the USGS. Since the USGS report was issued, another unconventional reservoir lying directly under the Bakken shale has also been found to produce crude oil in the Bakken field. We believe discovery of this additional reservoir called the Three Forks increases the potential barrels of crude oil that will ultimately be recovered from the Bakken Field. Crude oil production from the Bakken shale and Three Forks reservoirs is made possible through the combination of advanced horizontal drilling and fracture stimulation technology. Combining these two technologies to produce crude oil from the Bakken Field began to evolve in 2000. These horizontal wells are typically drilled on 320,640 or 1,280 acre spacing with horizontal laterals extending 4,500 to 9,500 feet into the reservoir. Fracture stimulation techniques vary but most commonly utilize multi-stage mechanically diverted stimulations using un-cemented liners and packers. During the month of August 2009, there were 1,586 horizontal wells producing approximately 185,200 barrels of crude oil equivalent per day from the Bakken shale and Three Forks in Montana and North Dakota. The Bakken Field remains one of the most actively drilled unconventional crude oil resource plays in the United States with 89 rigs drilling in the play as of January 25, 2010.

We plan to invest $513.4 million drilling 223 gross (87.3 net) wells in both the North Dakota and Montana portions of the Bakken field during 2010. As of January 25, 2010, we had 8 operated rigs drilling in the Bakken field. We plan to add 8 more rigs by midyear and therefore expect to have 16 rigs drilling in the Bakken field by midyear 2010. All but one of these rigs will be drilling in North Dakota. The other will be drilling in the Elm Coulee field in Montana.

North Dakota Bakken. In the North Dakota Bakken play, 2009 proved to be a pivotal year for us on many fronts. Production continued to grow to an average daily rate of 8,578 net Boe per day during the month of December 2009, up 60% from the average daily rate in December 2008. Proved reserves grew 503% year over year to 105.5 MMBoe as of December 31, 2009 as a result of our drilling success and reserve definition changes. We completed 100 gross (31.5 net) wells during the year, bringing our total to 253 gross (80.2 net) wells drilled in the field as of December 31, 2009. Our 2009 drilling program results substantially lowered our risk on the Nesson Anticline acreage allowing us to move into the development mode on much of this acreage. Our efforts to demonstrate that the Three Forks is a separate reservoir from the Middle Bakken also proved successful during the year, adding a second reservoir and incremental reserves for development. All totaled, our inventory of proven undeveloped locations stood at 616 gross (261.9 net) wells as of December 31, 2009. During the year we also saw the initial production rates from our wells increase due to improved completion technology and evolving geologic perspectives. The 7 day average initial rate for wells completed in the fourth quarter 2009 was 1,070 Boe per day as compared to 535 Boe per day for the average initial rate for wells completed in the fourth quarter 2008. During the fourth quarter 2009 our Hendrickson 1-36H well, in which we own 95% working interest, produced at an average rate of 1,990 Boe per day during its initial seven day test period. This is the highest rate recorded from our operated wells as of December 31, 2009. Based on historical well performance, we also increased our expected reserve model from 382 MBoe gross to 430 MBoe gross per well. On the cost side, drilling efficiencies developed and implemented by our technical staff during the year continued to cut drilling days per well. Our average spud to rig release was 26 days in the fourth quarter of 2009 down from 48 days for the same period in 2008 which lowered completed well costs by 28%.

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During 2010, we plan to invest $479.1 million drilling 218 gross (80.5 net) wells in the North Dakota Bakken field. The drilling will include development wells within our Nesson Anticline acreage and step-out wells designed to expand the field and further lower our risk on the acreage we have throughout the play. To date, the majority of our drilling has been on 1,280-acre spacing targeting either the Bakken shale or Three Forks reservoirs. Our development drilling in 2010 will continue to focus on developing both the Bakken and Three Forks reservoirs and will include a combination of 1,280-acre proven undeveloped locations and 640-acre infield locations. In time we expect that the North Dakota Bakken field will be developed on 320-acre spacing like the Elm Coulee field in Montana. Early in the year we plan to begin utilizing our trademarked ECO-Pad™ drilling sites that allow up to 4 wells to be drilled from a single location. The ECO-Pad™ concept minimizes the environmental impact while reducing drilling costs and increasing crude oil recovery.

As of December 31, 2009, we had 1,212,400 gross (481,800 net) acres in the North Dakota Bakken field, of which 20% of the net acreage is developed and 80% of the net acreage is undeveloped. We had 7 operated rigs drilling in the field as of January 25, 2010 and plan to have 15 rigs drilling in the field by midyear 2010.

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 14 th largest onshore field in the lower 48 states of the United States ranked by proved liquid reserves in 2008. Since drilling our first well in August 2003, we have completed a total of 160 gross (103.1 net) wells in the field as of December 31, 2009. Year over year, production in 2009 was down 11% reflecting our decision to defer development drilling in 2009 due to low crude oil prices.

In 2010, we plan to invest $34.3 million drilling 14 gross (6.8 net) wells in the Elm Coulee field. Drilling will be focused primarily on the 65 gross (44.7 net) proven undeveloped locations identified in the field as of December 31, 2009. We will also drill select locations to potentially expand the Elm Coulee field using improved completion technology developed in North Dakota. As of December 31, 2009, we held 128,900 gross (97,400 net) undeveloped acres adjacent to the Elm Coulee field. We had 1 operated rig drilling in the Elm Coulee field as of January 25, 2010, and plan to keep 1 rig drilling in the field throughout the year.

Big Horn Basin and Other Rockies

Our wells within the Big Horn Basin in northern Wyoming and other areas within the North region represented 5% of our PV-10 in the North region as of December 31, 2009 and 7% of our average daily North region Boe production for the three months ended December 31, 2009. During the three months ended December 31, 2009, we produced an average of 1,611 net Bbls of crude oil and 2,290 net Mcf of natural gas per day from our wells in the Big Horn Basin and other areas within the North 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 and horizontal Fryburg opportunities in North Dakota.

Conventional Lodgepole Mounds. During 2009, we participated in the discovery of a new producing Lodgepole mound in Stark County, North Dakota. The Laurine Engel 1-17, in which we own a 33% working interest, was completed flowing 463 Boe per day. This discovery is located near the prolific Dickinson Lodgepole fields that as of November 30, 2009 had produced 60 MMBoe from 41 wells for an average cumulative production of 1.46 MMBoe per well. This discovery was guided by 3D seismic and we have identified 3 potential locations for future drilling. We will spud the first of these 3 locations during the first quarter 2010 and plan to acquire more 3D seismic during the year to identify additional Lodgepole drilling opportunities.

Conventional Red River. The Red River is a well known conventional producing crude oil and natural gas reservoir throughout the Williston Basin of North Dakota and Montana. Though individual Red River wells have produced up to 1.5 million barrels of crude oil, the productive reservoir is generally confined to structural closures and structural-stratigraphic traps of 320 to 640 acres in size. The potential exists to find this type of conventional Red River production underlying our Bakken acreage in North Dakota and Montana. Identifying these Red River traps generally requires 3D seismic. We own or have under license 1,100 square miles of 3D seismic over portions of our acreage in Montana and North Dakota. As of December 31, 2009, we had interpreted approximately 10% of this data using our proprietary processing techniques and have identified 9 undrilled potential locations.

South Region

Our properties in the South region represented 5% of our PV-10 as of December 31, 2009 and 19% of our average daily Boe production for the three months ended December 31, 2009. During the three months ended December 31, 2009, our average daily production from such properties was 649 net Bbls of crude oil and 38,973 net Mcf of natural gas. Our principal producing properties in this region are located in the Anadarko and Arkoma Basins of Oklahoma, various basins of Texas and Louisiana.

Oklahoma Woodford Shale

The Oklahoma Woodford shale is a widespread unconventional reservoir found in various basins and geologic settings across the state of Oklahoma. The Woodford shale has long been recognized as a source rock for hydrocarbons but not until recently has technology allowed it to be targeted as a producing reservoir. As with other unconventional shale reservoirs, a combination of horizontal drilling and fracture stimulation technology is required to recover hydrocarbons from the shale. Depending on its thermal maturity, the Woodford shale can produce various combinations of crude oil, natural gas and natural gas condensate.

The largest occurrences of Woodford shale in Oklahoma are found in two geologic basins, the Arkoma Basin of eastern Oklahoma and the Anadarko Basin of western Oklahoma. Exploration and development of the Woodford shale started in the Arkoma Basin in 2005 with natural gas as the primary objective. During the month of July 2009, approximately 710 MMcf of natural gas per day and 281 Bbls of crude oil per day were being produced from 737 producing horizontal Woodford shale wells in the Arkoma Basin. Success from the Arkoma Basin soon translated to the Anadarko Basin, and in the fourth quarter 2007, a fracture stimulated, horizontal Woodford shale well was successfully completed as a producer in the Anadarko Basin. During the month of July 2009, approximately 40 MMcf of natural gas per day and 1,000 Bbls of crude oil per day were being produced from 53 horizontal Woodford shale wells in the Anadarko Basin. As of January 25, 2010, there were 25 rigs drilling horizontal Woodford shale wells in the Arkoma Basin and 15 rigs drilling horizontal Woodford shale wells in the Anadarko Basin.

As of December 31, 2009, we held 429,800 gross (198,500 net) acres in the Oklahoma Woodford shale play, of which 25% of the net acreage is developed and 75% of the net acreage is undeveloped. During 2010, we plan to invest $95.3 million drilling 73 gross (19.3 net) wells in the Oklahoma Woodford shale play and expect to have up to 4 operated rigs drilling in the play during the year.

Arkoma Woodford Shale. Since drilling our first well in February 2006, we have completed a total of 333 gross (49 net) wells in the Arkoma Woodford play through December 31, 2009. These wells represent 38% of the PV-10 in the South region as of December 31, 2009 and 61% of our average daily South region Boe production for the three months ended December 31, 2009. Production during the first quarter of 2009 averaged a record 4,799 Boe per day (28,793 Mcfe per day), up 153% over the same period in 2008. Following the first quarter, production gradually declined to an average of 3,573 Boe per day (21,439 Mcfe per day) during the fourth quarter, reflecting our scaled back 2009 drilling program and postponed completions. However, fourth quarter production was up 9% over the fourth quarter 2008 and year over year annual production was up 69% over 2008. As of December 31, 2009, we had 21 gross (3.1 net) wells waiting on completion.

During 2009, we completed a total of 71 gross (8.5 net) wells as compared to 130 gross (24.6 net) wells in 2008. These completions included a combination of 640 acre exploratory and 80 acre infield development type wells. We continued the use of simu-fracing when possible to more effectively stimulate and produce the Woodford shale while causing minimal disruption to existing producing wells. We also acquired 63 squares miles of 3D seismic data during 2009 that will provide critical guidance for our exploration and development drilling in the East McAlester area. As of December 31, 2009, we owned approximately 156,300 gross (44,800 net acres in the Arkoma Woodford play of which 47% is developed and 53% is undeveloped. A total of 401 gross (100.3 net) proven undeveloped locations have been identified on this acreage as of December 31, 2009.

In 2010, we plan to invest $56.2 million to drill 58 gross (12.0 net) wells in the Arkoma Woodford play. Approximately 46% of the drilling capital is targeted for development drilling with the balance focused on strategic step-out and exploratory drilling designed to secure acreage and delineate productive areas for future development. As of January 25, 2010, we had 2 operated rigs drilling in the Arkoma Woodford play and expect to keep 1 or 2 operated rigs drilling in the play throughout the year.

Anadarko Woodford Shale. The Anadarko Woodford shale continues to emerge as an unconventional reservoir capable of producing combinations of crude oil, natural gas and natural gas condensate throughout a large part of the Anadarko Basin. Guided by our geotechnical studies and drilling results, we have assembled one of the largest acreage positions in the Anadarko Woodford play with 244,800 gross (148,500 net) acres under lease as of December 31, 2009. This acreage is located in Canadian, Blaine, Dewey, Caddo, Grady and McClain Counties, Oklahoma. The Woodford shale underlying this acreage ranges from approximately 75 to 250 feet thick and occurs at depth ranging from 10,000 to 15,000 feet. As of December 31, 2009, industry drilling activity has been confined to an area covering approximately 360 square miles referred to as the Cana field in Canadian, Caddo and Blaine Counties, in Oklahoma. Results in the Cana field have been very positive with producing rates of up to 8.6 MMcfe of natural gas per day and reserves of up to 8 Bcfe per well being reported by various operators. As of October 2009, there have been 69 reported horizontal Woodford wells completed as producers in the Cana field area.

During 2009, we completed our first operated well in the Cana field area, the Young 2-22H, in which we own 54% working interest. This well completed flowing at an average rate of 6.8 MMcf of natural gas per day. To test our geotechnical theory that production from the Anadarko Woodford Shale is not confined to the Cana field area, we successfully completed the Brown 1-2H as a horizontal Woodford producer approximately 40 miles northwest of the Cana field in Dewey County, Oklahoma. The Brown 1-2H, in which we own 100% working interest, flowed at an average rate of 4.2 MMcf of natural gas per day and 102 Bbls of crude oil per day. The Brown 1-2H has performed similarly to producing wells in the Cana field and demonstrates the widespread productive potential for the Woodford shale in the Anadarko Basin and underlying our acreage. As of January 25, 2010 we were drilling a confirmation well five miles south of the Brown 1-2H and were also in the process of completing another horizontal Woodford shale well in Grady County, Oklahoma, approximately 30 miles southeast of the Cana field .

In 2010 we plan to invest $39.1 million to drill 15 gross (7.3 net) wells to continue to delineate the productive extents of the Anadarko Woodford shale on our acreage. As of January 25, 2010, we had 1 operated rig drilling in the Anadarko Woodford play and plan to have 2 additional rigs drilling in the play by mid-year 2010.

Haynesville Shale

The Haynesville shale play which began to evolve in late 2008 has become an established shale gas resource play located in the East Texas and North Louisiana Salt Basin of Northern Louisiana. Approximately 302 wells have been reported completed in the play by various operators with initial flowing at rates of up to 30 MMcfe per day as of November 2009. As with other unconventional shale reservoirs, a combination of horizontal drilling and fracture stimulation technology is required to produce the shale. We currently hold 26,300 gross (24,200 net) acres in the Haynesville shale play in Northern Louisiana. Approximately 2,200 net acres are located in what we currently consider the core of the play in Desoto Parish, Louisiana. During 2010, we plan to invest $16.6 million to drill 6 gross (1.5 net) horizontal Haynesville wells primarily in Desoto Parish where the Haynesville shale is found at a depth of approximately 11,350 feet and is on average 200 feet thick. We plan to initially develop the Desoto Parish acreage on 640-acre spacing but expect to be able to further develop the properties on 160-acre and possibly 80-acre spacing.

Conventional Anadarko Basin and Gulf Coast

Our conventional producing properties in the Anadarko Basin and Gulf Coast areas represented 51% of our PV-10 in the South region as of December 31, 2009 and 50% of our average daily South region equivalent production for the three months ended December 31, 2009. The properties include primarily our legacy assets in Oklahoma along the Anadarko Basin Shelf, the Jefferson Island Salt Dome in Iberia Parish, Louisiana and the producing properties in Nueces County, Texas. We continue to maximize the performance of these properties through workovers, recompletions and drilling as warranted.

East Region

Our properties in the East region represent 3% of our PV-10 as of December 31, 2009. During the three months ended December 31, 2009, our average daily production from such properties was 1,447 net Bbls of crude oil and 144 net Mcf of natural gas. Our principal producing properties in this region are located in the Illinois Basin, Michigan Basin, and portions of the Appalachian Basin in the eastern United States.

Illinois Basin

Our properties within the Illinois Basin represented 76% of the PV-10 in the East region as of December 31, 2009 and 71% of our average daily East region Boe production for the three months ended December 31, 2009. Our production within the Illinois Basin is primarily crude oil from units comprised of shallow sand formations under water injection. We continue to maximize the performance of these properties through workovers, recompletions and drilling as warranted.

Michigan Trenton-Black River

Our Trenton -Black River properties located in Hillsdale Co., Michigan represented 24% of the PV-10 in the East region as of December 31, 2009 and 29% of our average daily East region Boe production for the three months ended December 31, 2009. We owned approximately 76,500 gross (58,800 net) acres in the play as of December 31, 2009. Since drilling our first well on the properties in 2007, we have drilled and completed 12 gross (6.5 net) wells with net success of 78%. Drilling on these properties has been guided by our proprietary 3D seismic interpretation techniques. We currently own 39 square miles of 3D seismic data on the properties and have identified 19 potential drilling locations. We plan to acquire an additional 50 miles of 2D seismic and 14 square miles of 3D seismic during 2010 to identify additional drilling opportunities. During 2010, we plan to invest $5.3 million drilling 6 gross (5.0 net) wells of these seismically defined Trenton- Black River locations.

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Production and Price History

The following table sets forth summary information concerning our production results, average sales prices and production costs for the years ended December 31, 2009, 2008 and 2007:

	Year Ended December 31,		
	2009	2008	2007
Net production volumes:			
Oil (MBbls) [1]			
Cedar Hills	3,671	3,547	3,615
North Dakota Bakken	2,085	950	318
Arkoma Woodford	13	8	
Total Company	10,022	9,147	8,699
Natural gas (MMcf)			
Cedar Hills	2,236	2,076	666
North Dakota Bakken	1,680	605	209
Arkoma Woodford	9,152	5,407	1,821
Total Company	21,606	17,151	11,534
Oil equivalents (MBoe)			
Total Company	13,623	12,006	10,621
Average prices: [1]			
Oil ($/Bbl)			
Cedar Hills	$ 54.11	$ 88.50	$ 61.47
North Dakota Bakken	55.35	82.07	70.72
Arkoma Woodford	58.46	80.74	71.85
Total Company	54.44	88.87	63.55
Natural gas ($/Mcf)			
Cedar Hills	0.15	2.04	2.63
North Dakota Bakken	4.74	10.98	9.36
Arkoma Woodford	3.50	7.24	6.21
Total Company	3.22	6.90	5.87
Oil equivalents ($/Boe)			
Total Company	45.10	77.66	58.31
Costs and expenses [1]:			
Production expense ($/Boe)			
Cedar Hills	$ 7.05	$ 11.26	$ 9.74
North Dakota Bakken	2.36	10.71	11.44
Arkoma Woodford	2.10	7.87	4.33
Total Company	6.89	8.40	7.35
Production tax ($/Boe)	3.37	4.84	3.13
General and administrative expense ($/Boe) [2]	3.03	2.95	3.15
DD&A expense ($/Boe)	15.34	12.30	9.00

(1) Crude oil sales volumes vary from production volumes because at various times, we have stored crude oil in inventory due to pipeline line fill requirements or because of low prices or we have sold crude oil from inventory. Crude oil sales volumes were 82 MBbls less than production volumes for the year ended December 31, 2009, 97 MBbls more than production volumes for the year ended December 31, 2008 and 221 MBbls less than crude oil production volumes for the year ended December 31, 2007. Average prices and per unit costs have been calculated using sales volumes.

(2) General and administrative expense ($/Boe) includes non-cash equity compensation expense of $0.84 per Boe, $0.75 per Boe, and $1.23 per Boe for the years ended December 31, 2009, 2008 and 2007, respectively.

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The following table sets forth information regarding our average daily production during the fourth quarter of 2009:

	Fourth Quarter 2009		
	Crude Oil (Bbls)	Natural Gas (Mcf)	Total (Boe)
North:			
Red River units	13,177	6,433	14,249
Bakken field			
Montana Bakken	4,436	3,662	5,047
North Dakota Bakken	6,714	6,775	7,843
Other	1,611	2,290	1,993
South:			
Oklahoma Woodford			
Anadarko Woodford	57	4,096	740
Arkoma Woodford	19	21,325	3,573
Other	573	13,552	2,831
East	1,447	144	1,471
Total	28,034	58,277	37,747

Productive Wells

The following table presents the total gross and net productive wells by region and by crude oil or natural gas completion as of December 31, 2009:

	Oil Wells		Natural Gas Wells		Total Wells	
	Gross	Net	Gross	Net	Gross	Net
North:						
Red River units	251	230	2	2	253	232
Bakken field						
Montana Bakken	157	102	2	1	159	103
North Dakota Bakken	242	77	5	1	247	78
Other	296	261	5	1	301	262
South:						
Oklahoma Woodford						
Anadarko Woodford	2	2	6	3	8	5
Arkoma Woodford			318	47	318	47
Other	210	168	243	123	453	291
East	562	446	16	13	578	459
Total	1,720	1,286	597	191	2,317	1,477

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, 2009 we owned interests in no wells containing multiple completions.

Title to Properties

As is customary in the crude oil and natural 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

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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 crude oil and natural gas industry. Prior to completing an acquisition of producing crude 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 crude 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 crude oil production to end users at major market centers. Other production is sold to select midstream marketing companies or crude 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 crude oil that is directly marketed is transported by truck, the crude oil is delivered to the most practical point on a pipeline system for delivery to a sales point downstream on another connecting pipeline. Crude 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 2008 and the first quarter of 2009, as a result of pipeline constraints and a surge in area production, we shipped a portion of our North region crude oil by railcar. This strategy allowed us to keep all wells open and flowing and insured continued cash flows from production. By the second quarter of 2009, all of our crude oil production was transported either by pipeline or truck. All inventory fluctuations during this time period were a function of either intent or timing of new production and were managed. Our marketing of crude 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 *Item 1A. Risk factors Market conditions or operational impediments may hinder our access to crude oil and natural gas markets or delay our production.*

For the year ended December 31, 2009, crude oil sales to Marathon Crude Oil Company accounted for about 56% of our total revenues. No other purchasers accounted for more than 10% of our total crude oil and natural 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 crude 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 crude 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 crude oil and natural gas industry.

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Regulation of the Crude Oil and Natural Gas Industry

Regulation of Transportation of Crude 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 crude oil in common carrier pipelines is also subject to rate and access regulation. The Federal Energy Regulatory Commission, or the FERC, regulates interstate crude oil pipeline transportation rates under the Interstate Commerce Act. In general, interstate crude 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 crude oil that allowed for an increase or decrease in the cost of transporting crude oil to the purchaser. Intrastate crude oil pipeline transportation rates are subject to regulation by state regulatory commissions. The basis for intrastate crude oil pipeline regulation, and the degree of regulatory oversight and scrutiny given to intrastate crude 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 crude 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 crude 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 crude 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 crude 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. 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, on May 1 of each year, 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 at both the state and federal levels in the future. We cannot predict what effect, if any, such changes might have on our operations, but the industry could be required to incur additional capital expenditures and increased costs depending on future legislative and regulatory changes. We do not believe that we would be affected by any such regulatory changes materially differently than our competitors.

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, severance or excise 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.

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, including otherwise non-jurisdictional producers such as us, to use any deceptive or manipulative device or contrivance in connection with the purchase or sale of natural gas or the purchase or sale of transportation services subject to regulation by the FERC, in contravention of rules prescribed by FERC. 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.

EP Act 2005 also 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. Under EP Act 2005, FERC also has authority to order disgorgement of profits associated with any violation. The civil penalty provisions are applicable to entities that engage in the sale of natural gas for resale in interstate commerce. 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. Failure to comply with these reporting requirements could subject us to enhanced civil penalty liability provided under EP Act 2005.

FTC Market Manipulation Rules. Wholesale sales of petroleum are subject to provisions of the Energy Independence and Security Act of 2007 (EISA) and regulations by the Federal Trade Commission (FTC). Under the EISA, the FTC issued its Petroleum Market Manipulation Rule, which became effective November 4, 2009, and prohibits fraudulent or deceptive conduct (including false or misleading statements of material fact) in connection with wholesale purchases or sales of crude oil or refined petroleum products. The Rule also bans intentional failures to state a material fact when the omission makes a statement misleading and distorts or is likely to distort market conditions for any product covered by the Rule. The FTC holds substantial enforcement authority under the EISA.

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Additional proposals and proceedings that might affect the oil and 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 oil 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 crude 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 species of plants and animals; and
- require remedial measures to mitigate pollution from former and ongoing operations, such as requirements to close pits and plug abandoned wells.

These laws and regulations may also restrict the rate of crude oil and natural gas production below the rate that would otherwise be possible. The regulatory burden on the crude oil and natural 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 crude oil and natural 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 crude 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 solid and hazardous wastes and comparable state law; (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, 2009, we employed 408 people, including 222 employees in drilling and production, 57 in financial and accounting, 38 in land, 28 in exploration, 14 in reservoir engineering, 38 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 free of charge 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. 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 Crude Oil and Natural Gas Industry and Our Business

A substantial or extended decline in crude 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 crude oil and natural gas production heavily influences our revenue, profitability, access to capital and future rate of growth. Crude 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 crude 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 crude oil and natural gas;
- the actions of the Organization of Petroleum Exporting Countries, or OPEC;
- the price and quantity of imports of foreign crude oil and natural gas;
- political conditions in or affecting other crude 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 crude oil and natural gas exploration and production;
- the level of global crude 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.

The slowdown in economic activity caused by the worldwide economic recession has reduced worldwide demand for energy and resulted in lower crude oil and natural gas prices. Crude oil prices declined from record high levels in early July 2008 of over $140 per Bbl to below $45 per Bbl in February 2009 before rebounding to over $70 per Bbl in February 2010. Natural gas prices declined from over $13 per Mcf in mid-2008 to approximately $4 per Mcf in February 2009 before returning to over $5 per Mcf in February 2010.

Lower crude oil and natural gas prices will reduce our cash flows and borrowing ability. See *Item 1A. Risk Factors 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 crude oil and natural gas reserves*. Lower crude oil and natural gas prices may also reduce the amount of crude oil and natural gas that we can produce economically. Substantial decreases in crude 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 crude 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.

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In addition, because our producing properties are geographically concentrated in the North region, we are vulnerable to fluctuations in pricing in that area. In particular, 77% of our production during the fourth quarter of 2009 was from the North 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 crude oil produced from the wells in these areas. Such factors can cause significant fluctuation in our realized crude oil and natural gas prices. For example, the difference between the average NYMEX crude oil price and our average realized crude oil price for the year ended December 31, 2009 was $8.29 per Bbl, whereas the difference between the NYMEX crude oil price and our realized crude oil price for the year ended December 31, 2008 was $9.50 per Bbl.

Our estimates of proved reserves have been prepared under new SEC rules that went into effect for fiscal years ending on or after December 31, 2009, which may make comparisons to prior periods difficult and could limit our ability to book additional proved undeveloped reserves in the future.

This report presents estimates of our proved reserves as of December 31, 2009, which have been prepared and presented under new SEC rules. These new rules are effective for fiscal years ending on or after December 31, 2009, and require SEC reporting companies to prepare their reserves estimates using revised reserve definitions and revised pricing based on twelve-month unweighted first-day-of the-month average pricing. The previous rules required that reserve estimates be calculated using last-day-of the-year pricing. The pricing that was used for estimates of our reserves as of December 31, 2009 was based on an unweighted average twelve month NYMEX posted price of $61.18 per Bbl for oil ($52.76 per Bbl net of location differentials) and a NYMEX price of $3.87 per MMBtu for natural gas ($3.67 per Mcf net of location differentials), as compared to $44.60 per Bbl for oil ($39.69 per Bbl net of location differentials) and $5.62 per MMBtu for natural gas ($4.90 per Mcf net of location differentials) as of December 31, 2008. As a result of these changes, direct comparisons to our previously reported reserves amounts may be more difficult.

Another impact of the new SEC rules is a general requirement that, subject to limited exceptions, proved undeveloped reserves may only be booked if they relate to wells scheduled to be drilled within five years of the date of booking. This new rule may limit our potential to book additional proved undeveloped reserves as we pursue our drilling program, particularly as we develop our significant acreage in the North Dakota Bakken. Moreover, we may be required to write down our proved undeveloped reserves if we do not drill those reserves within the required five-year timeframe.

The SEC has not reviewed our or any reporting company s reserve estimates under the new rules and has released only limited interpretive guidance regarding reporting of reserve estimates under the new rules and may not issue further interpretive guidance on the new rules. Accordingly, while the estimates of our proved reserves at December 31, 2009 included in this report have been prepared based on what we and our independent reserve engineers believe to be reasonable interpretations of the new SEC rules, those estimates could differ materially from any estimates we might prepare applying more specific SEC interpretive guidance.

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 crude oil and natural gas reserves.

The crude 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 crude oil and natural gas reserves. Our cash flows used in investing activities was $507.0 million related to capital and exploration expenditures in 2009. Our budgeted capital expenditures for 2010 are expected to be approximately $850.0 million with $738.0 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

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drilling rigs and other services and equipment, and regulatory, technological and competitive developments. We expect our capital expenditures during 2010 to be significantly higher than our 2009 capital expenditures due to the acceleration of our drilling operations in 2010. We expect our cash flows from operations and the availability under our revolving credit facility will be sufficient to meet our capital expenditure needs. Continued improvement in commodity prices may result in an increase in our actual capital expenditures. Conversely, a significant decline in product prices could result in a decrease in our capital expenditures. We intend to finance our future capital expenditures primarily through cash flows 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 flows from operations be used for the payment of interest and principal on our debt, thereby reducing our ability to use cash flows 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 flows from operations and access to capital are subject to a number of variables, including:

- our proved reserves;
- the level of crude oil and natural gas we are able to produce from existing wells;
- the prices at which our crude 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 crude 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 crude oil and natural gas reserves, and could adversely affect our business, financial condition and results of operations.

Drilling for and producing crude 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 crude 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 crude 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 *Item 1A. Risk Factors 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;

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- 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 crude oil and natural gas prices;
- limited availability of financing at acceptable rates;
- title problems; and
- limitations in the market for crude 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 crude 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 Crude Oil and Natural Gas Operations, Proved Reserves* for information about our estimated crude oil and natural gas reserves and the PV-10 and standardized measure of discounted future net cash flows as of December 31, 2009.

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, based on historical data but projected into the future, about matters such as crude oil and natural gas prices, drilling and operating expenses, capital expenditures, taxes and availability of funds.

Actual future production, crude oil and natural gas prices, revenues, taxes, development expenditures, operating expenses and quantities of recoverable crude oil and natural gas reserves will vary from our estimates. Any significant 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 crude oil and natural gas prices and other factors, many of which are beyond our control.

The present value of future net revenues from our proved reserves will not necessarily be the same as the current market value of our estimated oil and natural gas reserves.

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. For the years prior to 2009, we based the estimated discounted future net revenues from our proved reserves on prices and costs in effect on the day of the estimate. In accordance with new SEC requirements, we currently base the estimated discounted future net revenues from our proved reserves on the 12-month unweighted arithmetic average of the first-day-of-the-month price for the preceding twelve months. Actual future net revenues from our oil and natural gas properties will be affected by factors such as:

- actual prices we receive for crude oil and natural gas;
- actual cost of development and production expenditures;

- the amount and timing of actual production; and
- changes in governmental regulations or taxation.

The timing of both our production and our incurrence of expenses in connection with the development and production of oil and natural gas properties will affect the timing and amount of actual future net revenues from proved reserves, and thus their actual present value. In addition, the 10% discount factor we use when calculating discounted future net revenues may not be the most appropriate discount factor based on interest rates in effect from time to time and risks associated with us or the oil and natural gas industry in general.

Actual future prices and costs may differ materially from those used in the present value estimate. If oil prices decline by $10.00 per Bbl, then our PV-10 as of December 31, 2009 would decrease approximately $622 million. If natural gas prices decline by $1.00 per Mcf, then our PV-10 as of December 31, 2009 would decrease approximately $181 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 crude 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 crude 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 crude 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 crude oil and natural gas prices decrease, we may be required to take write-downs of the carrying values of our crude oil and natural gas properties.

Accounting rules require that we periodically review the carrying value of our crude 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 crude 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 crude 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 crude oil and natural gas reservoirs generally are characterized by declining production rates that vary depending upon reservoir characteristics and other factors. Our future crude oil and natural gas reserves and production, and therefore our cash flows 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 crude 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 crude oil and natural gas exploration and production activities are subject to all of the operating risks associated with drilling for and producing crude oil and natural gas, including the possibility of:

- environmental hazards, such as uncontrollable flows of crude 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 crude oil or natural gas in commercially viable quantities.

Prospects that we decide to drill that do not yield crude 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 crude 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 crude oil or natural gas will be present or, if present, whether crude 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.

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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 crude oil and natural gas prices, the availability of capital, costs, drilling results, regulatory approvals and other factors. The North Dakota Bakken shale and Oklahoma 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 crude 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, 2009, we had leases representing 185,400 net acres expiring in 2010, 351,100 net acres expiring in 2011, and 238,300 net acres expiring in 2012. As such, our actual drilling activities may materially differ from those presently identified, which could adversely affect our business.

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

The marketability of our crude 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 crude 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 crude 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 flows, 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 flows.

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.

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

Our business is subject to federal, state, local and provincial laws and regulations as interpreted and enforced by governmental authorities possessing jurisdiction over various aspects of the exploration for, and the production and transportation of, crude 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 Crude 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.

Competition in the crude oil and natural gas industry is intense, making it more difficult for us to acquire properties, market crude 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 crude oil and natural gas and securing trained personnel. Also, there is substantial competition for capital available for investment in the crude 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 crude 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 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.

Crude oil and natural gas operations in the North region 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 crude 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 and 8 $^{1}/4$% Senior Notes due 2019 contain certain covenants, or restrictions 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.

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 flows used for drilling and place us at a competitive disadvantage. For example, as of February 19, 2010, outstanding borrowings under our revolving credit facility were $198.0 million and the impact of a 1% increase in interest rates on this amount of debt would result in increased interest expense of approximately $2.0 million and a $1.2 million decrease in our net income. 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.

Unrest in the financial markets 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 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 remain unsettled. Historically, we have used our cash flows 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 uncertainty could further reduce the demand for crude oil and natural gas and put downward pressure on the prices for crude 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 $750.0 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, which is solely at the discretion of our lenders, or (ii) an unwillingness or inability on the part of our lending counterparties to meet their funding obligations. Declines in commodity 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.

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 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.

Financial market turmoil has impacted the level of activity in the crude 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 ($59.8 million at December 31, 2009) and the sale of our crude oil and natural gas production ($125.8 million in receivables at December 31, 2009), 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

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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 crude oil and natural gas receivables with several significant customers. The largest purchaser of our crude oil and natural gas, during the twelve months ended December 31, 2009, accounted for 56% of our total revenues. We generally 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 crude oil and natural gas, we on occasion, enter into derivative instruments for a portion of our crude oil and/or natural gas production, including collars and price-fix swaps. In the second half of 2009 and January 2010, we entered into several commodity derivative transactions. See *Item 7. Management s Discussion and Analysis of Financial Condition and Results of Operations Oil and Gas Hedging* and *Notes to Consolidated Financial Statements Note 5. Derivative Instruments* for a summary of our crude oil and natural gas commodity derivative positions. We did not designate any of our derivative instruments as hedges for accounting purposes and we record all derivative instruments on our balance sheet at fair value. Changes in the fair value of our derivative instruments are 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 crude 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 crude oil and natural gas prices and their appropriate differentials;
- operating costs; and
- potential environmental and other liabilities.

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.

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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 19, 2010, Harold G. Hamm, our Chairman and Chief Executive Officer, beneficially owns 123,651,708 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.

Proposed legislation under consideration by Congress could increase our operating costs, reduce our liquidity, delay our operations or otherwise alter the way we conduct our business.

Our operations are subject to extensive federal, state and local laws and regulations. Changes to existing laws or regulations or new laws or regulations may unfavorably impact us and could result in increased taxes and operating costs and have a material adverse effect on our financial condition and results of operations. For example, Congress is currently considering legislation that, if adopted in its current proposed form, would subject companies involved in crude oil and natural gas exploration and production activities to substantial additional taxes and regulation. If such legislation is adopted, it could result in, among other items, additional regulation of and restrictions on hydraulic fracturing of wells, the elimination of certain U.S. federal tax incentives and deductions available to crude oil and natural gas exploration and production companies, and the prohibition or additional regulation of private energy commodity derivative and hedging activities. These and other potential laws and regulations could increase our taxes and operating costs, reduce our liquidity, delay our operations or otherwise alter the way we conduct our business, which could in turn have a material adverse effect on our financial condition, results of operations and cash flows.

Climate change legislation or regulations restricting emissions of greenhouse gases could result in increased operating costs and reduced demand for the oil, natural gas and NGLs that we produce.

On December 15, 2009, the U.S. Environmental Protection Agency (EPA) officially published its findings that emissions of carbon dioxide, methane and other greenhouse gases present an endangerment to human health and the environment because emissions of such gases are, according to the EPA, contributing to warming of the earth s atmosphere and other climatic changes. These findings by the EPA allow the agency to proceed with the adoption and implementation of regulations that would restrict emissions of greenhouse gases under existing provisions of the federal Clean Air Act. In late September 2009, the EPA had proposed two sets of regulations in anticipation of finalizing its findings that would require a reduction in emissions of greenhouse gases from motor vehicles and that could also lead to the imposition of greenhouse gas emission limitations in Clean Air Act permits for certain stationary sources. In addition, on September 22, 2009, the EPA issued a final rule requiring the reporting of greenhouse gas emissions from specified large greenhouse gas emission sources in the United States beginning in 2011 for emissions occurring in 2010. The adoption and implementation of any regulations imposing reporting obligations on, or limiting emissions of greenhouse gases from, our equipment and operations could require us to incur costs to reduce emissions of greenhouse gases associated with our operations or could adversely affect demand for the oil, natural gas and NGLs that we produce.

Also, on June 26, 2009, the U.S. House of Representatives passed the American Clean Energy and Security Act of 2009, or ACESA, which would establish an economy-wide cap-and-trade program to reduce U.S. emissions of greenhouse gases, including carbon dioxide and methane. ACESA would require a 17 percent reduction in greenhouse gas emissions from 2005 levels by 2020 and just over an 80 percent reduction of such emissions by 2050. Under this legislation, the EPA would issue a capped and steadily declining number of tradable emissions allowances to certain major sources of greenhouse gas emissions so that such sources could continue to emit greenhouse gases into the atmosphere. These allowances would be expected to escalate significantly in cost over time. The net effect of ACESA will be to impose increasing costs on the combustion of carbon-based fuels such as oil, refined petroleum products, and natural gas. The U.S. Senate has begun work on its own legislation for restricting domestic greenhouse gas emissions and the Obama Administration has indicated its support of legislation to reduce greenhouse gas emissions through an emission allowance system. Although it is not possible at this time to predict when the Senate may act on climate change legislation or how any bill passed by the Senate would be reconciled with ACESA, any future federal laws or implementing regulations that may be adopted to address greenhouse gas emissions could require us to incur increased operating costs and could adversely affect demand for the oil, natural gas and NGLs that we produce.

Even if such legislation is not adopted at the national level, more than one-third of the states, either individually or as part of regional initiatives, have begun taking actions to control and/or reduce emissions of greenhouse gases, as have a number of local governments. Although most of the regional and state-level initiatives have to date been focused on large sources of greenhouse gas emissions, such as coal-fired electric power plants, smaller sources of emissions could become subject to greenhouse gas emission limitations, allowance purchase requirements or other restrictions or costs. Any one of these climate change regulatory and legislative initiatives could have a material adverse effect on our business, financial condition and results of operations.

Finally, it should be noted that some scientists have concluded that increasing concentrations of greenhouse gases in the Earth s atmosphere may produce climate changes that have significant physical effects, such as increased frequency and severity of storms, droughts, and floods and other climatic events; if any such effects were to occur, they could have an adverse effect on our assets and operations.

The adoption of derivatives legislation by Congress could have an adverse impact on our ability to hedge risks associated with our business.

Congress currently is considering broad financial regulatory reform legislation that among other things would impose comprehensive regulation on the over-the-counter (OTC) derivatives marketplace and could affect the use of derivatives in hedging transactions. The financial regulatory reform bill adopted by the House of Representatives on December 11, 2009, would subject swap dealers and major swap participants to substantial supervision and regulation, including capital standards, margin requirements, business conduct standards, and recordkeeping and reporting requirements. It also would require central clearing for transactions entered into between swap dealers or major swap participants. For these purposes, a major swap participant generally would be someone other than a dealer who maintains a substantial net position in outstanding swaps, excluding swaps used for commercial hedging or for reducing or mitigating commercial risk, or whose positions create substantial net counterparty exposure that could have serious adverse effects on the financial stability of the U.S. banking system or financial markets. The House-passed bill also would provide the Commodity Futures Trading Commission (CFTC) with express authority to impose position limits for OTC derivatives related to energy commodities. Separately, in late January, 2010, the CFTC proposed regulations that would impose speculative position limits for certain futures and option contracts in natural gas, crude oil, heating oil, and gasoline. These proposed regulations would make an exemption available for certain *bona fide* hedging of commercial risks. Although it is not possible at this time to predict whether or when Congress will act on derivatives legislation or the CFTC will finalize its proposed regulations, any laws or regulations that subject us to additional capital or margin requirements relating to, or to additional restrictions on, our trading and commodity positions could have an adverse effect on our ability to hedge risks associated with our business or on the cost of our hedging activity.

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Item 1B. Unresolved Staff Comments

There were no unresolved Securities and Exchange Commission staff comments at December 31, 2009.

Item 2. Properties

The information required by Item 2 is contained in *Item 1. Business Crude Oil and Natural 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 2009.

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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 and cash dividends declared for each quarter of the previous two years.

	2009				2008			
	First Quarter	Second Quarter	Third Quarter	Fourth Quarter	First Quarter	Second Quarter	Third Quarter	Fourth Quarter
High	$ 26.97	$ 34.41	$ 44.31	$ 47.27	$ 32.06	$ 76.01	$ 83.81	$ 39.74
Low	13.84	20.00	22.33	36.25	20.55	30.55	31.44	12.01
Cash Dividend								

Our 8 1/4% Senior Notes Due 2019 may restrict payment of dividends and we do not anticipate paying any cash dividends on our common stock in the foreseeable future. As of February 16, 2010, the number of record holders of our common stock was 67. Management believes, after inquiry, that the number of beneficial owners of our common stock is approximately 22,000. On February 19, 2010, the last reported sales price of our Common Stock, as reported on the NYSE, was $40.96 per share. The following table summarizes our purchases of our common stock during the fourth quarter of 2009:

Period	(a) Total number of shares purchased (1)	(b) Average price paid per share (2)	(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 (3)
October 1, 2009 to October 31, 2009	54,479	$ 39.59		
November 1, 2009 to November 30, 2009	11,849	$ 38.61		
December 1, 2009 to December 31, 2009	22,735	$ 42.58		
Total	89,063	$ 40.22		

(1) In connection with stock option exercises or restricted stock grants under the Continental Resources, Inc. 2000 Stock Option Plan (2000 Plan) and the Continental Resources, Inc. 2005 Long-Term Incentive Plan (2005 Plan), we adopted a policy that enables employees to surrender shares to cover their tax liability. See *Notes to Consolidated Financial Statements Note 13. Stock Compensation*. The 2000 Plan was adopted in October 2000 and was terminated in November 2005. The 2005 Plan was adopted in October 2005 and expires in October 2015. All shares purchased above represent shares surrendered to cover tax liabilities. We paid the associated taxes to the Internal Revenue Service.

(2) The price paid per share was the closing price of our common stock on the date of exercise or the date the restrictions lapsed on such shares, as applicable.

(3) We are unable to determine at this time the total amount of securities or approximate dollar value of those securities that could potentially be surrendered to us pursuant to our policy that enables employees to surrender shares to cover their tax liability associated with the exercise of options or vesting of restrictions on shares under the 2000 Plan and 2005 Plan.

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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, 2005 through 2009, 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,				
	2009	**2008**	**2007**	**2006**	**2005**
Statement of Income :					
(in thousands, except per share data)					
Oil and natural gas sales	$ 610,698	$ 939,906	$ 606,514	$ 468,602	$ 361,833
Derivative losses[1]	(1,520)	(7,966)	(44,869)		
Total revenues	626,211	960,490	582,215	483,652	375,764
Income from continuing operations	71,338	320,950	28,580	253,088	194,307
Net Income	71,338	320,950	28,580	253,088	194,307
Basic earnings per share:					
From continuing operations	$ 0.42	$ 1.91	$ 0.17	$ 1.60	$ 1.23
Net income per share	$ 0.42	$ 1.91	$ 0.17	$ 1.60	$ 1.23
Shares used in basic earnings per share	168,559	168,087	164,059	158,114	158,059
Diluted earnings per share:					
From continuing operations	$ 0.42	$ 1.89	$ 0.17	$ 1.59	$ 1.22
Net income per share	$ 0.42	$ 1.89	$ 0.17	$ 1.59	$ 1.22
Shares used in diluted earnings per share	169,529	169,392	165,422	159,665	159,307
Pro forma C-corporation[2]					
Pro forma income from continuing operations			$ 184,002	$ 156,833	$ 121,177
Pro forma net income			184,002	156,833	121,177
Pro forma basic earnings per share			1.12	0.97	0.77
Pro forma diluted earnings per share			1.11	0.96	0.76
Production[3]					
Oil (MBbl)	10,022	9,147	8,699	7,480	5,708
Gas (MMcf)	21,606	17,151	11,534	9,225	9,006
Oil equivalent (MBoe)	13,623	12,006	10,621	9,018	7,209
Average sales prices					
Oil ($/Bbl)	$ 54.44	$ 88.87	$ 63.55	$ 55.30	$ 52.45
Gas ($/Mcf)	3.22	6.90	5.87	6.08	6.93
Oil equivalent ($/Boe)	45.10	77.66	58.31	52.09	50.19
Average costs per Boe ($/Bbl)[4]					
Production expense	$ 6.89	$ 8.40	$ 7.35	$ 6.99	$ 7.32
Production tax	3.37	4.84	3.13	2.48	2.22
Depreciation, depletion, amortization and accretion	15.34	12.30	9.00	7.27	6.91
General and administrative	3.03	2.95	3.15	3.45	4.34
Proved reserves					
Oil (MBbl)	173,280	106,239	104,145	98,038	98,645
Gas (MMcf)	504,080	318,138	182,819	121,865	108,118
Oil equivalent (MBoe)	257,293	159,262	134,615	118,349	116,665
Other financial data (in thousands):					
Cash dividends per share	$	$	$ 0.33	$ 0.55	$ 0.01
EBITDAX[5]	450,648	757,708	469,885	372,115	285,344
Net cash provided by operations	375,858	719,915	390,648	417,041	265,265
Net cash used in investing	(499,822)	(927,617)	(483,498)	(324,523)	(133,716)
Net cash provided by (used in) financing	132,957	204,170	94,568	(91,451)	(141,467)
Capital expenditures	433,991	988,593	525,677	326,579	144,800

Balance sheet data at December 31 (in thousands):					
Total assets	$ 2,314,927	$ 2,215,879	$ 1,365,173	$ 858,929	$ 600,234
Long-term debt, including current maturities	523,524	376,400	165,000	140,000	143,000
Shareholders equity	1,030,279	948,708	623,132	490,461	324,730

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(1) Derivative losses in 2007, 2008 and 2009 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 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) At various times, we have stored crude oil due to pipeline line fill requirements or because of low prices or we have sold crude oil from inventory. These actions result in differences between our produced and sold crude oil volumes as noted. For the year 2009, crude oil sales volumes were 82 MBbls less than crude oil production volumes. For the year 2008, crude oil sales volumes were 97 MBbls more than crude oil production volumes. For the years 2007, and 2006, crude oil sales volumes were 221 MBbls and 21 MBbls less than crude oil production volumes, respectively.
(4) Average costs per Boe have been computed using sales volumes.
(5) 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 flows 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 flows 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, 2009, our Total Funded Debt to EBITDAX ratio was approximately 1.2 to 1. The following table represents a reconciliation of our net income to EBITDAX for the periods presented:

	Year ended December 31,				
	2009	2008	2007	2006	2005
	(in thousands)				
Net income	$ 71,338	$ 320,950	$ 28,580	$ 253,088	$ 194,307
Interest expense	23,232	12,188	12,939	11,310	14,220
Provision (benefit) for income taxes	38,670	197,580	268,197	(132)	1,139
Depreciation, depletion, amortization and accretion	207,602	148,902	93,632	65,428	49,802
Property impairments	83,694	28,847	17,879	11,751	6,930
Exploration expense	12,615	40,160	9,163	19,738	5,231
Unrealized derivative loss	2,089		26,703		
Equity compensation	11,408	9,081	12,792	10,932	13,715
EBITDAX	$ 450,648	$ 757,708	$ 469,885	$ 372,115	$ 285,344

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. For a discussion of oil and gas reserve information, please see *Item 1. Business.*

Overview

We are engaged in crude oil and natural gas exploration, exploitation and production activities in the North, South and East regions of the United States. Crude oil comprised 67% of our 257.3 MMBoe of estimated proved reserves as of December 31, 2009 and 74% of our 13,623 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 93% of our PV-10 and 72% of our 2,317 gross wells as of December 31, 2009. 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, 2009, we added 181,777 MBoe of proved reserves through

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extensions and discoveries, compared to 2,301 MBoe added through purchases. During this period, our production increased from 10,621 MBoe in 2007 to 13,623 MBoe in 2009. An aspect of our business strategy has been to acquire large undeveloped acreage positions in new or developing resource plays. As of December 31, 2009, we held approximately 2,165,800 gross (1,094,300 net) undeveloped acres, including 485,300 net undeveloped acres in the Bakken field in Montana and North Dakota and 149,000 net undeveloped acres in the Oklahoma Woodford 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, 2009, our crude oil and natural gas production increased to 13,623 MBoe (37,324 Boe per day), up 14% from the year ended December 31, 2008. The increase in 2009 production primarily resulted from an increase in production from our Red River units, North Dakota Bakken field and Oklahoma Woodford. Crude oil and natural gas revenues for 2009 decreased by 35% to $610.7 million due to decreases in commodity prices. Our realized price per Boe decreased $32.56 to $45.10 for 2009 compared to 2008. We experienced decreases in production expense and production tax of a combined total of $21.4 million, or 13%. Our decrease in combined per unit cost was 23%, or $2.98 per Boe, due to the increase in sales volumes of 1,438 MBoe, or 12%. At various times we have stored crude oil due to pipeline line fill requirements or because of low prices or we have sold oil from inventory. These actions result in differences between our produced and sold crude oil volumes as noted. Crude oil sales volumes were 82 MBbls less than crude oil production for the year ended December 31, 2009 and crude oil sales volumes were 97 MBbls more for the same period in 2008. Our cash flows from operating activities for the year ended December 31, 2009, was $375.9 million, a decrease of $344.0 million from $719.9 million provided by our operating activities during the comparable 2008 period. The decrease in operating cash flows was mainly due to decreases in sales prices by 42% partially offset by an increase in sales volumes. During the year ended December 31, 2009, we invested $434.0 million (inclusive of non-cash accruals of $74.7 million) in our capital program concentrating mainly in the Red River units, the Bakken field and the Oklahoma Woodford play.

Our 2010 capital expenditures budget of $850 million will primarily focus on increased development in the North Dakota Bakken, the Arkoma and Anadarko Woodford shale natural gas plays in Oklahoma and the Red River units, with total operated drilling rigs increasing to as many as 23 by mid-year 2010. We expect our cash flows from operations and the availability under our revolving credit facility will be sufficient to meet our capital expenditure needs. Continued strength in commodity prices may result in an increase in our actual capital expenditures during 2010; conversely, a significant decline in product prices could result in a decrease in our capital expenditures. See *Item 7. Management s Discussion and Analysis of Financial Condition and Results of Operation Liquidity and Capital Resources*.

In September 2009, we issued $300 million of 8 $^{1}/4$ % Senior Subordinated Notes due 2019 (Notes) for net proceeds of approximately $289.7 million, after deducting the underwriters discounts of approximately $6.8 million and offering expenses of approximately $1.0 million. The net proceeds were used to repay a portion of the borrowings outstanding under our revolving credit facility.

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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 crude oil and natural gas produced, (2) crude 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, 2009.

	Year ended December 31,		
	2009	2008	2007
Average daily production:			
Oil (Bbl per day)	27,459	24,993	23,832
Natural gas (Mcf per day)	59,194	46,861	31,599
Oil equivalents (Boe per day)	37,324	32,803	29,099
Average prices:(1)			
Oil ($/Bbl)	$ 54.44	$ 88.87	$ 63.55
Natural gas ($/Mcf)	3.22	6.90	5.87
Oil equivalents ($/Boe)	45.10	77.66	58.31
Production expense ($/Boe)(1)	6.89	8.40	7.35
General and administrative expense ($/Boe)(1) (2)	3.03	2.95	3.15
EBITDAX (in thousands)(3)	450,648	757,708	469,885
Net income (in thousands)(4)	71,338	320,950	28,580
Pro forma net income (in thousands)(5)			184,002
Diluted net income per share	0.42	1.89	0.17
Pro forma diluted net income per share(5)			1.11

(1) At various times, we have stored crude oil due to pipeline line fill requirements or because of low prices or we have sold crude oil from inventory. These actions result in differences between our produced and sold crude oil volumes as noted. Crude oil sales volumes were 82 MBbls less than crude oil production for the year ended December 31, 2009, crude oil sales volumes were 97 MBbls more than crude oil production for the year ended December 31, 2008 and 221 MBbls less than crude oil production for the year ended December 31, 2007. Average prices and per unit expenses have been calculated using sales volumes and excluding any effect of derivative transactions.

(2) General and administrative expense ($/Boe) includes non-cash equity compensation expense of $0.84 per Boe, $0.75 per Boe, and $1.23 per Boe for the years ended December 31, 2009, 2008 and 2007, respectively.

(3) EBITDAX represents earnings before interest expense, income taxes, 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 flows as determined by GAAP. A reconciliation of net income to EBITDAX is provided in *Item 6. Selected Financial Data.*

(4) Prior to our initial public offering, we were a subchapter S corporation and income taxes were payable by our shareholders. 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.

(5) Pro forma adjustments are reflected to provide for income taxes in accordance with authoritative accounting guidance 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, 2009:

	Year Ended December 31,		
(in thousands, except volume and price data)	**2009**	**2008**	**2007**
Oil and natural gas sales	$ 610,698	$ 939,906	$ 606,514
Derivatives	(1,520)	(7,966)	(44,869)
Total revenues	626,211	960,490	582,215
Operating costs and expenses	493,923	431,167	274,248
Other expense	22,280	10,793	11,190
Net income, before income taxes	110,008	518,530	296,777
Provision for income taxes(1)	38,670	197,580	268,197
Net income	$ 71,338	$ 320,950	$ 28,580
Production Volumes:			
Oil (MBbl)	10,022	9,147	8,699
Natural gas (MMcf)	21,606	17,151	11,534
Oil equivalents (MBoe)	13,623	12,006	10,621
Sales Volumes:			
Oil (MBbl)	9,940	9,244	8,478
Natural gas (MMcf)	21,606	17,151	11,534
Oil equivalents (MBoe)	13,541	12,103	10,400
Average Prices:(2)			
Oil ($/Bbl)	$ 54.44	$ 88.87	$ 63.55
Natural gas ($/Mcf)	$ 3.22	$ 6.90	$ 5.87
Oil equivalents ($/Boe)	$ 45.10	$ 77.66	$ 58.31

(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) At various times, we have stored crude oil due to pipeline line fill requirements or because of low prices or we have sold crude oil from inventory. These actions result in differences between our produced and sold crude oil volumes as noted. Crude oil sales volumes were 82 MBbls less than crude oil production for the year ended December 31, 2009, crude oil sales volumes were 97 MBbls more than crude oil production for the year ended December 31, 2008 and 221 MBbls less than crude oil production for the year ended December 31, 2007. Average prices have been calculated using sales volumes and excluding any effect of derivative transactions.

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Year ended December 31, 2009 compared to the year ended December 31, 2008

Production

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

	Year Ended December 31,					
	2009		2008		Volume	Percent
	Volume	Percent	Volume	Percent	increase	increase
Crude Oil (MBbl)	10,022	74%	9,147	76%	875	10%
Natural Gas (MMcf)	21,606	26%	17,151	24%	4,455	26%
Total (MBoe)	13,623	100%	12,006	100%	1,617	13%

	Year Ended December 31,				Volume	Percent
	2009		2008		increase	increase
	MBoe	Percent	MBoe	Percent	(decrease)	(decrease)
North	10,314	76%	9,246	77%	1,068	12%
South	2,784	20%	2,225	19%	559	25%
East	525	4%	535	4%	(10)	(2)%
Total (MBoe)	13,623	100%	12,006	100%	1,617	13%

Crude oil production volumes increased 10% during the year ended December 31, 2009 compared to the year ended December 31, 2008. Production increases in the Bakken field area contributed incremental volumes in excess of production for the same period in 2008 of 1,055 MBoe. Favorable results from drilling have been the primary contributors to production growth in this area. Natural gas volumes increased 4,455 MMcf, or 26%, during the year ended December 31, 2009 compared to the same period in 2008. The majority of the increase, 3.6 Bcf of natural gas, was from the South region due to the results of our exploration efforts in the Oklahoma Woodford play. The North region natural gas production was up 0.8 Bcf for the year ended December 31, 2009 compared to the same period in 2008 mainly due to additional natural gas being connected and sold in the North Dakota Bakken area.

Revenues

Crude Oil and Natural Gas Sales. Crude oil and natural gas sales for the year ended December 31, 2009 were $610.7 million, a 35% decrease from sales of $939.9 million for 2008. Our sales volumes increased 1,438 MBoe or 12% over the same period in 2008 due to the continuing success of our enhanced oil recovery and drilling programs and additional natural gas being connected and sold in the North region. Our realized price per Boe decreased $32.56 to $45.10 for the year ended December 31, 2009 from $77.66 for the year ended December 31, 2008. The differential between NYMEX calendar month average crude oil prices and our realized crude oil price per barrel for the year ended December 31, 2009 was $8.29 compared to $9.50 for 2008. Factors contributing to the changing differentials included Canadian crude oil imports and increases in production in the North region, coupled with downstream transportation capacity constraints, refinery downtime in the North region, and seasonal demand fluctuations for gasoline.

Derivatives. We are required to recognize 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. As a result, we mark our derivative instruments to fair value and recognize the realized and unrealized changes in fair value on derivative instruments in the income statements under the caption Loss on mark-to-market derivative instruments.

During the year ended December 31, 2009, we realized gains on gas derivatives of $0.6 million. We reported an unrealized non-cash mark-to-market gain on gas derivatives of $1.6 million and an unrealized non-cash mark-to-market loss on oil derivatives of $3.7 million.

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Crude Oil and Natural Gas Service Operations. Our crude oil and natural gas service operations consist primarily of the treatment and sale of lower quality crude oil, or reclaimed crude oil, and the sales of high-pressure air. Prices for reclaimed crude oil sold from our central treating unit were lower for the year ended December 31, 2009 than the comparable 2008 period. The price decreased $45.30 per barrel from 2008 to 2009 which decreased reclaimed crude oil income by $10.2 million contributing to an overall decrease in crude oil and natural gas service operations revenue of $11.5 million for the year ended December 31, 2009. Associated crude oil and natural gas service operations expenses decreased $7.5 million to $10.7 million during the year ended December 31, 2009 from $18.2 million during the year ended December 31, 2008 due mainly to a decrease in the costs of purchasing and treating crude oil for resale compared to the same period in 2008. We sold high-pressure air from our Red River units to a third party and recorded revenues of $2.2 million for the year ended December 31, 2009 compared to revenues of $3.0 million for the year ended December 31, 2008.

Operating Costs and Expenses

Production Expense, Production Tax and Other Expenses. Production expense decreased $8.4 million, or 8%, during the year ended December 31, 2009 to $93.2 million from $101.6 million during the year ended December 31, 2008. The decrease in production expense was mainly attributable to reductions in energy costs, repairs and workovers. During the year ended December 31, 2009, we participated in the completion of 217 gross (67.8 net) wells. Production expense per Boe decreased to $6.89 for the year ended December 31, 2009 from $8.40 per Boe for the year ended December 31, 2008.

Production tax and other expenses decreased $13.0 million, or 22%, during the year ended December 31, 2009 compared to the year ended December 31, 2008 as a result of lower revenues resulting from decreased sales prices partially offset by the expiration of various tax incentives and increases in other charges. Production tax and other expenses on the consolidated income statement includes other charges for marketing, gathering, dehydration and compression fees primarily related to natural gas sales in the Arkoma Woodford area of $6.8 million and $3.4 million for the years ended December 31, 2009 and 2008, respectively. Production tax, excluding other expenses, as a percentage of crude oil and natural gas sales was 6.5% for the year ended December 31, 2009 compared to 6.0% for the year ended December 31, 2008. 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 crude oil or natural 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 tax and other expenses were as follows:

	Year Ended December 31,		
$/Boe	**2009**	**2008**	**Percent decrease**
Production expense	$ 6.89	$ 8.40	(17)%
Production tax and other expense	3.37	4.84	(30)%
Production expense, production tax and other expenses	$ 10.26	$ 13.24	(23)%

Exploration Expense. Exploration expense consists primarily of dry hole costs and exploratory geological and geophysical costs that are expensed as incurred. Exploration expense decreased $27.6 million in the year ended December 31, 2009 to $12.6 million due primarily to a decrease in seismic expense of $14.9 million to $2.0 million and a decrease in dry hole expense of $13.5 million to $6.5 million. The majority of the dry hole costs, 67%, were in the East region for the year ended December 31, 2009 and 67% of the dry hole costs for the 2008 period were in the North region.

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Depreciation, Depletion, Amortization and Accretion (DD&A). Total DD&A increased $58.7 million in the year ended December 31, 2009 compared to the same period in 2008, primarily due to an increase in production volumes and additional properties with higher cost reserves being added through our drilling program. Additionally, DD&A increased as a result of the decrease in commodity prices used to calculate reserve volumes at December 31, 2008 that affected DD&A for the first six months of 2009. Lower prices have the effect of decreasing the economic life of crude oil and natural gas properties, which lowers future reserve volumes and increases DD&A. The following table shows the components of our DD&A rate per Boe.

	Year Ended December 31,		
$/Boe	**2009**	**2008**	**Percent increase**
Crude oil and natural gas	$ 14.94	$ 11.91	25%
Other equipment	0.23	0.22	5%
Asset retirement obligation accretion	0.17	0.17	0%
Depreciation, depletion, amortization and accretion	$ 15.34	$ 12.30	25%

Property Impairments. Property impairments, non-producing and developed, increased in the year ended December 31, 2009 by $54.9 million to $83.7 million compared to $28.8 million during the year ended December 31, 2008. Impairment of non-producing properties increased $30.6 million during the year ended December 31, 2009 to $47.1 million compared to $16.5 million for 2008 reflecting higher amortization of lease costs in our existing fields resulting from further defining likely drilling locations, capital constraints, 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 crude oil and natural gas properties were approximately $36.6 million for the year ended December 31, 2009 compared to approximately $12.3 million for the year ended December 31, 2008, an increase of $24.3 million, or 198%. We evaluate our developed crude oil and natural 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 2009 reflect uneconomic drilling results in certain small fields primarily in our South region and our Rockies Other area in the North region, which resulted in impairments of $36.6 million in 2009. Impairments in 2008 were primarily related to uneconomic wells in our South region and our Rockies Other area in the North region.

General and Administrative Expense. General and administrative expense increased $5.4 million to $41.1 million during the year ended December 31, 2009 from $35.7 million during the comparable period of 2008. General and administrative expense includes non-cash charges for stock-based compensation of $11.4 million and $9.1 million for the years ended December 31, 2009 and 2008, respectively. General and administrative expense excluding equity compensation increased $3.7 million for the twelve months ended December 31, 2009 compared to the twelve months ended December 31, 2008. The increase was primarily related to an increase in personnel costs of approximately $2.0 million due to additional employees and higher wages and increased benefits along with an increase in donations of approximately $1.0 million and an increase in professional fees including litigation expense of approximately $1.5 million. On a volumetric basis, general and administrative expense was $3.03 per Boe for the year ended December 31, 2009 compared to $2.95 per Boe for the year ended December 31, 2008.

Interest Expense. Interest expense increased 91%, or $11.0 million, for the year ended December 31, 2009 compared to the year ended December 31, 2008, due to increased debt partially offset by lower interest rates in 2009. Our average revolving credit facility balance increased to $426.3 million for the year ended December 31, 2009 compared to $248.7 million for the year ended December 31, 2008, but the weighted average interest rate on our revolving credit facility was 1.64% lower at 2.90% for the year ended December 31, 2009 compared to

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4.54% for the same period in 2008. At December 31, 2009, our outstanding balance under our revolving credit facility was $266.0 million with a weighted average interest rate of 2.66%. On September 23, 2009, we issued $300 million of 8 1/4% Senior Notes due 2019 (Notes). The Notes, which carry a coupon rate of 8.25%, were sold at a discount (99.16% of par), which equates to an effective yield to maturity of approximately 8.375%. We recorded $7.0 million in interest on the Notes for the year ended December 31, 2009. Including the effect of the Notes, our weighted average interest rate for the year ended December 31, 2009 was 3.78% while at December 31, 2009 our weighted average rate was 5.92%.

Income Taxes. Income taxes for the year ended December 31, 2009 were $38.7 million compared to $197.6 million for the year ended December 31, 2008. We provide taxes at a combined federal and state tax rate of approximately 35% for 2009 compared to approximately 38% for 2008 after taking into account permanent taxable differences. The decrease in the effective tax rate is related to state losses and utilization of state net operating loss carry forwards. See *Notes to Consolidated Financial Statements Note 8. Income Taxes* for more information.

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

For the year ended December 31, 2009, we changed our reporting regions from Rockies, Mid-Continent and Gulf Coast to North, South and East. The primary effect of this change was to combine the Mid-Continent and Gulf Coast regions into the South region and to split the East region from the new South region. Where appropriate, the following discussion has been revised from our previous filings to reflect this change.

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
Crude 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
North	9,246	77%	8,619	81%	627	7%
South	2,225	19%	1,588	15%	637	40%
East	535	4%	414	4%	121	29%
Total (MBoe)	12,006	100%	10,621	100%	1,385	13%

Crude 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 North area contributed incremental volumes in excess of 2007 levels of 313 MBbls, including 219 MBbls which came from the Bakken field. The South 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. Natural 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 South region due to the results of our exploration efforts in the Arkoma Woodford. The North region natural gas production was up 1.9 Bcf for the year ended December 31, 2008 compared to 2007 due to additional natural 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 natural gas from the Red River units through the new plant.

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Revenues

Crude Oil and Natural Gas Sales. Crude 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 crude 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 crude oil imports, increases in production in the North region, coupled with downstream transportation capacity constraints, refinery downtime in the North region, and reduced seasonal demand for gasoline.

Derivatives. In July 2007, we entered into fixed-price swap contracts covering 10,000 barrels of crude 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 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.

Crude Oil and Natural Gas Service Operations. Our crude 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 crude 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 crude 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 crude oil income by $6.5 million contributing to an overall increase in crude oil and natural gas service operations revenue of $8.0 million for the year ended December 31, 2008. Associated crude 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 crude 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 South and North 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 crude 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 crude oil or natural 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:

	Year Ended December 31,		Percent
($/Boe)	**2008**	**2007**	**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 North region for the years ended December 31, 2008 and 2007.

Depreciation, Depletion, Amortization and Accretion (DD&A). Total DD&A increased $55.3 million in 2008 primarily due to an increase in crude oil and natural 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 crude oil and natural 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**
Crude oil and natural 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 crude oil and natural 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 crude oil and natural 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 South region and our Rockies Other area which resulted in impairments of $8.8 million in 2008. The significant decrease in crude oil and natural 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 Coast area in the South region and certain small fields primarily in our South 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 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.

Liquidity and Capital Resources

Our primary sources of liquidity have been cash flows generated from operating activities, financing provided by our revolving credit facility, and the issuance of the Notes in September 2009. As we exited the fourth quarter of 2008, crude oil and natural gas prices had declined significantly from their record levels which reduced our operational cash flows. In response, we began reducing capital expenditures during the last quarter of 2008 and prepared our capital expenditure budget for 2009 assuming lower commodity prices. During the second quarter of 2009 we began to see increases in crude oil prices to levels double the first quarter lows; however, natural gas prices remained depressed. Since crude oil accounts for more than 70% of our production, the price increase resulted in improved cash flows from operations and better liquidity. Additionally, we were able to increase our revolving credit facility commitment from $672.5 million to $750.0 million during the second quarter of 2009.

Our current revolving credit facility is backed by a syndicate of 15 banks, which approved an increase in our borrowing base from $850.0 million to $1.0 billion effective December 1, 2009. We believe that our current syndicate banks have the capability to fund up to our current commitment of $750.0 million. If one or more banks should not be able to do so, we may not have the full availability of $750.0 million commitment. On September 23, 2009, we issued $300.0 million of 8 $^{1}/4$% Senior Notes due 2019 and received net proceeds of approximately $289.7 million after deducting underwriters discounts and other expenses and after giving effect to the discount at which the Notes were issued. The net proceeds were used to repay a portion of the borrowings outstanding under our revolving credit facility. As of December 31, 2009, we had $523.4 million available under our revolving credit facility and $16.3 million in working capital. During the first quarter of 2009, we had rig commitments on up to 6 rigs. Five of the contracts expired in 2009 and we currently have one remaining rig contract that expires in August 2011. Our current plan is to expand capital expenditures in a measured manner without long-term rig commitments. This will allow us to adapt rapidly to commodity price changes or other external factors. During 2009, we experienced reductions in crude oil field service costs, including drilling costs, compared to 2008.

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 flows 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. Lower crude oil and natural gas prices will reduce our cash flows and borrowing ability. Although our average realized price received for crude oil and natural gas was $45.10 per Boe for the year ended December 31, 2009, it was effected by lower crude oil prices for the first half of the year. In the fourth quarter of 2009, our average realized price received for crude oil and natural gas was $56.69 per Boe. Furthermore, the issuance of additional debt may require that a portion of our cash flows from operations be used for the payment of interest and principal on our debt, thereby reducing our ability to use cash flows 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. Please see *Item 1A. Risk Factors 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 crude oil and natural gas reserves*.

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. Declines in commodity 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.

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 Flows from Operating Activities

Our net cash provided by operating activities was $375.9 million, $719.9 million and $390.6 million for the years ended December 31, 2009, 2008 and 2007, respectively. The decrease in operating cash flows for the year ended December 31, 2009 was mainly due to decreases in revenue as a result of lower commodity prices as explained above.

Cash Flows from Investing Activities

During the years ended December 31, 2009, 2008 and 2007 we had cash flows used in investing activities (excluding asset sales) of $507.0 million, $930.8 million and $486.4 million, respectively, in our capital program, inclusive of dry hole costs. The decrease in our cash flows used in investing activities for the year ended December 31, 2009 was mainly due to decreases in capital expenditures as a result of lower commodity prices in 2009.

Cash Flows from Financing Activities

Net cash provided by financing activities of $133.0 million for the year ended December 31, 2009, was mainly the result of amounts received from the issuance of the Notes less amounts repaid under our revolving credit facility to fund capital expenditures, including the reduction in accounts payable. Net cash provided by financing activities of $204.2 million for the year ended December 31, 2008 was mainly the results of borrowings 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.

Revolving Credit Facility

We had $226.0 million and $376.4 million outstanding under our revolving credit facility at December 31, 2009 and 2008, respectively. The decrease was largely due to the repayment of a portion of the outstanding borrowings under our revolving credit facility with the net proceeds from the issuance of the Notes in September 2009. As of February 19, 2010, the amount outstanding under our credit facility had decreased by $28.0 million to $198.0 million.

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, 2009 and 2008, we had cash and cash equivalents of $14.2 million and $5.2 million, respectively, and available borrowing capacity on our revolving credit facility of $523.4 million and $176.1 million, respectively. At February 19, 2010, we had available borrowing capacity on our revolving credit facility of $551.2 million. We anticipate that we will negotiate a new revolving credit facility during the second quarter of 2010 as our current revolving credit facility matures in April 2011.

The revolving credit facility was amended in December 2009 to increase the borrowing base from $850.0 million to $1.0 billion, subject to semi-annual redetermination. Borrowings under the revolving credit facility are secured by liens on substantially all of our crude oil and natural gas properties and associated assets. Our next semi-annual redetermination will occur in April 2010. 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 note amount remains at $750.0 million which is also our commitment level.

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, 2009, we were in compliance with all covenants.

8 1/4% Senior Subordinated Notes due 2019

On September 23, 2009, the Company issued $300 million of the Notes. The Notes, which carry a coupon rate of 8.25%, were sold at a discount (99.16% of par), which equates to an effective yield to maturity of approximately 8.375%. The Company received net proceeds of approximately $289.7 million, after deducting the underwriters discounts of approximately $6.8 million and offering expenses of approximately $1.0 million. The net proceeds were used to repay a portion of the borrowings outstanding under our revolving credit facility.

The Notes will mature on October 1, 2019, and interest is payable on the Notes on each April 1 and October 1, commencing April 1, 2010. The Company has the option to redeem all or a portion of the Notes at any time on or after October 1, 2014 at the redemption price specified in the Indenture dated September 23, 2009 (the Indenture) plus accrued and unpaid interest. The Company may also redeem the Notes, in whole or in part, at a make-whole redemption price specified in the Indenture, plus accrued and unpaid interest, at any time prior to October 1, 2014. In addition, the Company may redeem up to 35% of the Notes prior to October 1, 2012 under certain circumstances with the net cash proceeds from certain equity offerings. The Indenture contains certain restrictions on our ability to incur additional debt, pay dividends on our common stock, make investments, create liens on our assets, engage in transactions with our affiliates, transfer or sell assets, consolidate or merge, or sell substantially all of our assets. These covenants are subject to a number of important exceptions and qualifications. The Company was in compliance with these covenants as of December 31, 2009. The Notes are not subject to any sinking fund requirements. Our subsidiary, which currently has no independent assets or operations, fully and unconditionally guarantees this debt.

Capital Expenditures and Commitments

We evaluate opportunities to purchase or sell crude 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 $434.0 million (inclusive of non-cash accruals of $74.7 million) for capital and exploration expenditures in 2009 as follows:

In millions	Amount
Exploration and development drilling	$ 301.8
Dry holes	6.5
Acquisition of producing properties	1.2
Capital facilities, workovers and re-completions	24.6
Land costs	89.9
Seismic	2.0
Vehicles, computers and other equipment	8.0
Total	$ 434.0

Expenditures for exploration and development of crude oil and natural gas properties are the primary use of our capital resources. In response to significantly lower crude oil and natural gas prices during the first half of 2009 and the resulting decrease in expected cash flows, we reduced our capital expenditures budgeted from $609.0 million in 2008 to $275.0 million for 2009. In August 2009, when crude oil prices and our cash flows began to increase, we increased our budget to $390.0 million. In November 2009, we increased our budget again to $415.0 million with the majority of the additional spending directed at drilling operations in the North Dakota Bakken.

Cash flows from operations as shown on our statements of cash flows was negatively impacted by payments made to reduce prior year accruals and was less than our capital expenditures for the year ended December 31, 2009. However, when you consider the $74.7 million in non-cash December 31, 2008 accruals paid in 2009, cash generated from current year operating activities exceeded our capital expenditures.

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Based on strong cash flows and our positive outlook, in November 2009, our Board of Directors approved a preliminary 2010 capital expenditures budget of $650.0 million. In February 2010, our Board of Directors increased the capital expenditures budget to $850 million in order to accelerate our drilling program as follows:

In millions	Amount
Exploration and development drilling	$ 671
Capital facilities, workovers and re-completions	67
Land costs	92
Seismic	9
Vehicles, computers and other equipment	11
Total	$ 850

Our 2010 budgeted capital expenditures are approximately 95% higher than the $434.0 million invested during 2009. We plan to invest approximately $671 million in drilling of which 77% will be invested in the Bakken field, 14% in the Oklahoma Woodford play, 5% in the Red River units and 4% in various other plays

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 2010 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 flows, actual drilling results, the availability of drilling rigs and other services and equipment, and regulatory, technological and competitive developments.

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, 2009:

		Payments due by period			
	Total	Less than 1 year	1 - 3 years	3 - 5 years	More than 5 years
			In thousands		
Revolving credit facility	$ 226,000	$	$ 226,000	$	$
Senior Notes due 2019[1]	300,000				300,000
Interest expense[2]	249,072	30,762	51,231	49,500	117,579
Operating leases	1,428	1,048	288	92	
Drilling rig commitments[3]	14,553	8,943	5,610		
Asset retirement obligations[4]	50,167	2,460	8,754	1,088	37,865
Total contractual cash obligations	$ 841,220	$ 43,213	$ 291,883	$ 50,680	$ 455,444

(1) Does not reflect the discount at which the Notes were issued.

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(2) Interest expense includes interest on the Notes and revolving credit facility and assumes that the interest rate of 2.66% at December 31, 2009 continues for the life of the revolving credit facility.

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

(4) Amounts represent expected asset retirements by period.

Oil and Gas Hedging

As part of our risk management program, we hedge a portion of our anticipated future crude oil and natural gas production for the next 12-24 months to reduce our exposure to fluctuations in crude oil and natural gas prices. In addition, we may utilize basis contracts to hedge the differential between the NYMEX posted prices and those of our physical pricing points. Reducing our exposure to price volatility helps ensure that we have adequate funds available for our capital programs and more price sensitive drilling programs. Our decision on the quantity and price at which we choose to hedge our future production is based in part on our view of current and future market conditions.

While the use of these hedging arrangements limits the downside risk of adverse price movements, their use also may limit future revenues from favorable price movements. In addition, the use of hedging transactions may involve basis risk. All of our hedging transactions have been carried out in the over-the-counter market. The use of hedging transactions also involves the risk that the counterparties will be unable to meet the financial terms of such transactions. Our derivative contracts are with multiple counterparties to minimize our exposure to any individual counterparty. Substantially all of our hedging transactions are settled based upon reported settlement prices on the NYMEX.

Between January 1, 2010 and February 19, 2010, we entered into additional crude oil and natural gas derivative contracts summarized in the table below. None of these contracts have been designated for hedge accounting.

Crude Oil

			Collars			
			Floors		Ceilings	
Period and Type of Contract	**Volume in MBbls**	**Swaps Weighted Average**	**Range**	**Weighted Average**	**Range**	**Weighted Average**
January 2010 March 2010						
Swaps	343	$ 84.00	$	$	$	$
Collars	148		75.00	75.00	96.40	96.40
April 2010 June 2010						
Swaps	410	84.22				
Collars	228		75.00	75.00	96.40	96.40
July 2010 September 2010						
Swaps	414	84.22				
Collars	598		75.00	75.00	94.50 - 96.40	95.23
October 2010 December 2010						
Swaps	414	84.22				
Collars	598		75.00	75.00	94.50 - 96.40	95.23

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Natural Gas

Period and Type of Contract	Volume in MMMBtus	Swaps Weighted Average
January 2010 March 2010		
Swaps	590	$ 5.86
April 2010 December 2010		
Swaps	3,163	5.85
January 2011 December 2011		
Swaps	11,863	6.36

Please see *Notes to Consolidated Financial Statements Note 5. Derivative Contracts* appearing later in this report for more discussion and tables and a description of the accounting applicable to our hedging program, a listing of open contracts as of December 31, 2009 and the estimated fair market value of those contracts as of that date.

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 crude oil and natural gas reserve estimations, revenue recognition, the choice of accounting method for derivatives and crude 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.

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

Our independent engineers and technical staff prepare the estimates of our crude oil and natural gas reserves and associated future net cash flows. Current accounting guidance allows only proved crude 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, natural gas and natural gas liquids which geological and engineering data demonstrate with reasonable certainty to be recoverable in future years from known reservoirs under existing economic and operating conditions. 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. Crude oil and natural gas reserve engineering is a subjective process of estimating underground accumulations of crude 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, crude 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 crude oil and natural 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.

In addition, the SEC has not reviewed our reserve estimates, or any reporting company s reserve estimates, under the new rules and has released only limited interpretive guidance regarding reporting of reserve estimates under the new rules and may not issue further interpretive guidance on the new rules. Accordingly, while the estimates of our proved reserves at December 31, 2009 included in this report have been prepared based on what we and our independent reserve engineers believe to be reasonable interpretations of the new SEC rules, those estimates could differ materially from any estimates we might prepare applying more specific SEC interpretive guidance.

Revenue Recognition

We derive substantially all of our revenues from the sale of crude oil and natural gas. Crude oil and natural 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.

Derivative Activities

We sometimes utilize derivative contracts to hedge against the variability in cash flows associated with the forecasted sale of our future crude oil and natural gas production. We may hedge a portion of our anticipated crude oil and natural gas production for the next 12-24 months. In addition, we may utilize basis contracts to hedge the differential between the NYMEX Henry Hub posted prices and those of our physical pricing points. We do not use derivative instruments for trading purposes. Under accounting rules, we may elect to designate those derivatives that qualify for hedge accounting as cash flow hedges against the price that we will receive for our future crude oil and natural gas production. We have elected not to designate any future price risk management activities as accounting hedges. Because our derivative contracts are not designated for hedge accounting they are accounted for on a mark-to-market basis through the income statements, we are likely to experience significant non-cash volatility in our reported earnings during periods of commodity price volatility. Derivative assets and liabilities with the same counterparty and subject to contractual terms which provide for net settlement are reported on a net basis on our consolidated balance sheet.

In determining the amounts to be recorded for our open hedge contracts, we are required to estimate the fair value of the derivative. We use a third party to provide our derivative valuations. Their valuation models for derivative contracts are primarily industry-standard models that consider various inputs including: (a) quoted forward prices for commodities, (b) time value, (c) volatility factors, and (d) current market and contractual prices for the underlying instruments, as well as other relevant economic measures. The calculation of the fair value of our option contracts requires the use of an option-pricing model. The estimated future prices are compared to the prices fixed by the hedge agreements and the resulting estimated future cash inflows or outflows over the lives of the hedges are discounted to calculate the fair value of the derivative contracts. These pricing and discounting variables are sensitive to market volatility as well as changes in future price forecasts, regional price differences and interest rates. We validate our valuations by comparison to our counterparty marks and management reviews.

Successful Efforts Method of Accounting

We use the successful efforts method of accounting for our crude oil and natural gas properties, including enhanced recovery projects, whereby costs to acquire mineral interests in crude oil and natural gas properties, drill and equip exploratory wells or projects that find proved reserves and to drill and equip development wells or projects and expenditures for enhanced recovery operations are capitalized. Geological and geophysical costs, seismic costs, lease rentals and costs associated with unsuccessful exploratory wells or projects, including enhanced recovery projects, are expensed as incurred. Maintenance, repairs and costs of injection are expensed as incurred, except that the cost of replacements or renewals that expand capacity or improve production are capitalized.

Depreciation, depletion and amortization, or DD&A, of capitalized drilling and development costs of crude oil and natural gas properties are generally computed using the unit of production method on a field basis based on total estimated proved developed crude 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 crude 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 crude 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 crude oil and natural gas properties. We base our estimate of the liability on our historical experience in abandoning crude oil and natural 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 crude oil and natural 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. For producing properties the evaluations involve a significant amount of judgment since the results are based on estimated future events, such as future sales prices for crude oil and natural gas, future costs to produce these products, estimates of future crude 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 crude 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.

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

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amortized on a composite method based on the Company s estimated experience of successful drilling and the average holding period. The estimate of successful drilling rate is highly judgmental and subject to material revision in future periods as better information becomes available.

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, 2009, 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 crude 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 taxpaying 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.

Off-Balance Sheet Arrangements

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

Recent Accounting Pronouncements Not Yet Adopted

For a description of the accounting standards that we adopted in 2009, see *Notes to Consolidated Financial Statements Note 1. Organization and Summary of Significant Accounting Policies*.

In January 2010, the Financial Accounting Standards Board issued Accounting Standards Update No. 2010-06 which amended the authoritative accounting guidance related to fair value measurements and disclosures. The update requires new disclosures about transfers in and out of Level 1 and Level 2 fair value measurements and additional disaggregation of activity in Level 3 fair value measures. It also provides clarification about existing disclosures. The disclosures and clarifications will be effective for us for our year ended December 31, 2010 except for the disaggregation disclosures of activity in Level 3 fair value measures which will be effective for us for the year ended December 31, 2011.

Inflation

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

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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.

Commodity Price Risk. Our primary market risk exposure is in the pricing applicable to our crude oil and natural gas 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 crude oil and natural gas 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, 2009, our annual revenue would increase or decrease by approximately $100.0 million for each $10.00 per barrel change in crude oil prices and $22.0 million for each $1.00 per MMBtu change in natural gas prices.

To partially reduce price risk caused by these market fluctuations, we may hedge a portion of our anticipated crude oil and natural gas production for the next 12-24 months as part of our risk management program. In addition, we may utilize basis contracts to hedge the differential between NYMEX Henry Hub posted prices and those of our physical pricing points. We may use hedging to reduce our exposure to fluctuations in crude oil and natural gas prices. Reducing our exposure to price volatility helps ensure that we have adequate funds available for our capital programs and more price sensitive drilling programs. Our decision on the quantity and price at which we choose to hedge our production is based in part on our view of current and future market conditions. While hedging limits the downside risk of adverse price movements, it also may limit future revenues from favorable price movements. The use of hedging transactions also involves the risk that counterparties, which generally are financial institutions, will be unable to meet the financial terms of such transactions. Our derivative contracts are with multiple counterparties to minimize our exposure to any individual counterparty.

For the year ended December 31, 2009, we realized gains on gas derivatives of $0.6 million. We reported an unrealized non-cash mark-to-market gain on gas derivatives of $1.6 million and an unrealized non-cash mark-to-market loss on oil derivatives of $3.7 million. The fair value of our derivative instruments at December 31, 2009 was a liability of $2.1 million. A 10% increase or decrease in the future prices used in the valuation would have increased the liability to $25.4 million or changed the valuation to a receivable of $19.9 million, respectively.

For a further discussion of our hedging activities, see information under the caption *Item 7. Management s Discussion and Analysis of Financial Condition and Results of Operations Oil and Gas Hedging* of this report and the discussion and tables in *Notes to Consolidated Financial Statements Note 5. Derivative Instruments* appearing later in this report.

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 ($59.8 million at December 31, 2009) and the sale of our crude oil and natural gas production, which we market to energy marketing companies, refineries and affiliates ($125.8 million in receivables at December 31, 2009). 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 interest in the well to redirect production proceeds in

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order to secure payment or, if necessary, foreclose on the interest. Historically, our credit losses on joint interest receivables have been immaterial.

We monitor our exposure to counterparties on crude 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 crude oil and natural gas sales receivables owed to us.

Interest Rate Risk. Our exposure to changes in interest rates relates primarily to long-term debt obligations. We may utilize interest rate derivatives to alter interest rate exposure in an attempt to reduce interest rate expense related to existing debt issues. Interest rate derivatives are used solely to modify interest rate exposure and not to modify the overall leverage of the debt portfolio. We are exposed to changes in interest rates as a result of our revolving credit facility. We had revolving credit facility debt of $198.0 million outstanding under our revolving credit facility at February 19, 2010. The impact of a 1% increase in interest rates on this amount of debt would result in increased interest expense of approximately $2.0 million per year and a $1.2 million decrease in net income. Our revolving credit facility matures in 2011 and the weighted-average interest rate at February 19, 2010 was 3.09%. On September 23, 2009, we issued $300 million of 8 $^{1}/4$% Senior Notes due 2019. The Notes, which carry a coupon rate of 8.25%, were sold at a discount of 99.16% of par and equates to an effective yield to maturity of approximately 8.375%. Interest is payable on the Notes on each April 1 and October 1, commencing April 1, 2010. The following table presents our long-term debt maturities and the weighted average interest rates by expected maturity date:

In thousands	2010	2011	2012	2013	2014	Thereafter	Total
Fixed rate debt:							
Senior Notes:							
Principal amount [1]	$	$	$	$	$	$ 300.0	$ 300.0
Weighted-average interest rate						8.25%	8.25%
Variable rate debt:							
Revolving credit facility:							
Principal amount	$	$ 226.0	$	$	$	$	$ 226.0
Weighted-average interest rate		2.66%					2.66%

(1) This amount does not reflect the discount at which the Notes were issued of ($2.5) million.

Changes in interest rates affect the amount we pay on borrowings under our revolving credit facility. All of our other long-term indebtedness is fixed rate and does not expose us to the risk of cash flow loss due to changes in market interest rates. However, changes in interest rates do affect the fair value of our debt.

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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, 2009 and 2008, and the related consolidated statements of income, shareholders equity and cash flows for each of the three years in the period ended December 31, 2009. 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, 2009 and 2008, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2009 in conformity with accounting principles generally accepted in the United States of America.

As discussed in Note 1, the Company changed its method of estimating oil and gas reserves and related disclosures in 2009.

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, 2009, 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, 2010 expressed an unqualified opinion.

/s/ GRANT THORNTON LLP

Oklahoma City, Oklahoma

February 26, 2010

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Continental Resources, Inc. and Subsidiary

Consolidated Balance Sheets

	December 31, 2009	December 31, 2008
	(In thousands, except par values and share data)	
Assets		
Current assets:		
Cash and cash equivalents	$ 14,222	$ 5,229
Receivables:		
Oil and natural gas sales	119,565	63,659
Affiliated parties	7,823	14,914
Joint interest and other, net	58,188	150,506
Inventories	26,711	22,210
Deferred and prepaid taxes	4,575	18,810
Prepaid expenses and other	4,944	2,367
Total current assets	236,028	277,695
Net property and equipment, based on successful efforts method of accounting	2,068,055	1,935,143
Debt issuance costs, net	10,844	3,041
Total assets	$ 2,314,927	$ 2,215,879
Liabilities and shareholders equity		
Current liabilities:		
Accounts payable trade	$ 91,248	$ 260,188
Accounts payable trade to affiliated parties	9,612	25,730
Accrued liabilities and other	49,601	34,769
Revenues and royalties payable	66,789	78,160
Current portion of asset retirement obligation	2,460	4,747
Total current liabilities	219,710	403,594
Long-term debt	523,524	376,400
Other noncurrent liabilities:		
Deferred tax liability	489,241	445,752
Asset retirement obligation, net of current portion	47,707	39,883
Other noncurrent liabilities	4,466	1,542
Total other noncurrent liabilities	541,414	487,177
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, 169,968,471 shares issued and outstanding at December 31, 2009; 169,558,129 shares issued and outstanding at December 31, 2008	1,700	1,696
Additional paid-in capital	430,283	420,054
Retained earnings	598,296	526,958
Total shareholders equity	1,030,279	948,708
Total liabilities and shareholders equity	$ 2,314,927	$ 2,215,879

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,		
	2009	**2008**	**2007**
	In thousands, except per share data		
Revenues:			
Oil and natural gas sales	$ 584,089	$ 875,213	$ 572,610
Oil and natural gas sales to affiliates	26,609	64,693	33,904
Loss on mark-to-market derivative instruments	(1,520)	(7,966)	(44,869)
Oil and natural gas service operations	17,033	28,550	20,570
Total revenues	626,211	960,490	582,215
Operating costs and expenses:			
Production expenses	76,719	80,935	57,562
Production expense to affiliates	16,523	20,700	18,927
Production tax and other expenses	45,645	58,610	32,562
Exploration expense	12,615	40,160	9,163
Oil and natural gas service operations	10,740	18,188	12,709
Depreciation, depletion, amortization and accretion	207,602	148,902	93,632
Property impairments	83,694	28,847	17,879
General and administrative	41,094	35,719	32,802
Gain on sale of assets	(709)	(894)	(988)
Total operating costs and expenses	493,923	431,167	274,248
Income from operations	132,288	529,323	307,967
Other income (expense):			
Interest expense	(23,232)	(12,188)	(12,939)
Other	952	1,395	1,749
	(22,280)	(10,793)	(11,190)
Income before income taxes	110,008	518,530	296,777
Provision for income taxes	38,670	197,580	268,197
Net income	$ 71,338	$ 320,950	$ 28,580
Basic net income per share	$ 0.42	$ 1.91	$ 0.17
Diluted net income per share	$ 0.42	$ 1.89	$ 0.17
Pro forma (unaudited, Note 1):			
Income before income taxes			$ 296,777
Provision for income taxes			112,775
Net income			$ 184,002
Basic net income per share			$ 1.12
Diluted net income per share			$ 1.11

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, 2007	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
Net income				71,338		71,338
Stock-based compensation			11,408			11,408
Tax benefit on share-based compensation plan			2,872			2,872
Stock options:						
Exercised	138,010	1	244			245
Repurchased and canceled	(29,924)		(1,223)			(1,223)
Restricted stock:						
Issued	411,217	4				4
Repurchased and canceled	(83,457)	(1)	(3,072)			(3,073)
Forfeited	(25,504)					

Balance, December 31, 2009	169,968,471	$ 1,700	$ 430,283	$ 598,296	$	$ 1,030,279

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, 2009	2008	2007
	In thousands		
Cash flows from operating activities:			
Net income	$ 71,338	$ 320,950	$ 28,580
Adjustments to reconcile net income to net cash provided by operating activities:			
Depreciation, depletion, amortization and accretion	208,885	148,573	95,604
Property impairments	83,694	28,847	17,879
Change in derivative fair value	2,089	(26,703)	26,703
Equity compensation	11,408	9,081	12,791
Tax benefit of excess nonqualified stock option deduction			(1,630)
Provision for deferred income taxes	36,119	184,115	262,412
Dry hole costs	6,477	20,002	3,549
Other, net	1,898	(114)	(331)
Changes in assets and liabilities:			
Accounts receivable	48,738	(65,989)	(74,004)
Inventories	(4,501)	(3,834)	(11,288)
Prepaid expenses and other	21,961	(16,520)	(2,837)
Accounts payable	(117,643)	101,967	(7,760)
Revenues and royalties payable	(11,371)	10,811	38,611
Accrued liabilities and other	13,842	8,545	2,009
Other noncurrent liabilities	2,924	184	360
Net cash provided by operating activities	375,858	719,915	390,648
Cash flows from investing activities:			
Exploration and development	(497,496)	(841,479)	(477,663)
Purchase of oil and gas properties	(1,217)	(74,662)	(4,166)
Purchase of other property and equipment	(8,257)	(14,651)	(4,610)
Proceeds from sale of assets	7,148	3,175	2,941
Net cash used in investing activities	(499,822)	(927,617)	(483,498)
Cash flows from financing activities:			
Revolving credit facility	426,100	443,000	288,500
Repayment of revolving credit facility	(576,500)	(231,600)	(263,500)
Proceeds from initial public offering, net			124,495
Issuance of 8 $^{1}/4$% Senior Notes due 2019, net	297,480		
Other debt	3,304		
Repayment of other debt	(3,304)		
Debt issuance costs	(10,028)	(1,717)	(90)
Repurchase of equity grants	(4,299)	(6,748)	(5,075)
Dividends to shareholders	(41)	(207)	(52,036)
Exercise of options	245	1,442	644
Tax benefit of excess nonqualified stock option deduction			1,630
Net cash provided by financing activities	132,957	204,170	94,568
Effect of exchange rate changes on cash and cash equivalents			25
Net change in cash and cash equivalents	8,993	(3,532)	1,743
Cash and cash equivalents at beginning of period	5,229	8,761	7,018
Cash and cash equivalents at end of period	$ 14,222	$ 5,229	$ 8,761

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

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Continental Resources, Inc. and Subsidiary

Notes to Consolidated Financial Statements

1. Organization and Summary of Significant Accounting Policies

Description of Company

Continental Resources, Inc. (the Company) is incorporated under the laws of the State of Oklahoma. It was originally formed in 1967 to explore, develop and produce crude 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 North region. Approximately 76% of its estimated proved reserves as of December 31, 2009 are located in the North region. As of December 31, 2009, the Company had interests in 2,317 wells and serves as the operator of 1,661 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, Banner Pipeline Company, L. L. C., at December 31, 2009, which currently has no assets or operations. The consolidated financial statements include the accounts of Continental and its wholly owned subsidiary after all significant inter-company accounts and transactions have been eliminated.

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 crude oil and natural gas reserves, which is used to compute depreciation, depletion, amortization and impairment on producing crude oil and natural 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 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 income tax effects) were used for the pro forma enacted tax rate. 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.

Continental Resources, Inc. and Subsidiary

Notes to Consolidated Financial Statements (continued)

Revenue recognition

Crude oil and natural gas sales result from interests owned by the Company in crude oil and natural gas properties. Sales of crude oil and natural gas produced from crude oil and natural gas operations are recognized when the product is delivered to the purchaser and title transfers to the purchaser. Payment is generally received 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 received are recorded in the month payment is received. 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, 2009 and 2008 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 crude oil and natural gas exploration and production related activities. Crude 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, 2009, 2008 and 2007 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, 2009	$ 193,126	$	$	$ 193,126
Year ended December 31, 2008	193,326		(200)	193,126
Year ended December 31, 2007	193,326			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 crude oil and natural gas production accounted for 56% (one purchaser), 44% (one purchaser) and 44% (three purchasers) of total revenues for 2009, 2008 and 2007, respectively. These purchasers constituted all purchasers with sales in excess of 10% of total revenues. The Company does not require collateral and does not believe the loss of any single purchaser would materially impact its operating results, as crude oil and natural gas are fungible products with well-established markets and numerous purchasers.

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Continental Resources, Inc. and Subsidiary

Notes to Consolidated Financial Statements (continued)

Inventories

Inventories are stated at the lower of cost or market and consists of the following:

	December 31, 2009	December 31, 2008
	In thousands	
Tubular goods and equipment	$ 12,044	$ 14,884
Crude oil	14,667	7,326
	$ 26,711	$ 22,210

As of December 31, 2009, our total crude oil inventory of 398,000 barrels valued at $14**.7** million consisted of approximately 253,000 barrels of line fill requirements and 145,000 barrels of temporarily stored crude oil. As of December 31, 2008, our total crude oil inventory of 275,000 barrels valued at $7.3 million consisted of approximately 230,000 barrels of line fill requirements and 45,000 barrels of temporarily stored crude oil. Our inventory, including line fill, is valued at the lower of cost or market using the FIFO inventory method.

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

Crude Oil and natural gas properties

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

As required, the Company reports capitalized exploratory drilling costs on the balance sheet. 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, 2009 and 2008, pending the

Continental Resources, Inc. and Subsidiary

Notes to Consolidated Financial Statements (continued)

determination of proved reserves were $22.9 million and $46.3 million, respectively. As of December 31, 2009, exploratory drilling costs of $2.4 million representing 3 wells were suspended one year beyond the completion of drilling and are expected to be fully evaluated in 2010. Of the suspended costs, $0.1 million was incurred in 2007, $1.8 million was incurred in 2008 and the balance in 2009.

Production expenses are those costs incurred by the Company to operate and maintain its crude 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 is required to account for its asset retirement obligations by recording 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 crude oil and natural 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 crude 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, 2007 through December 31, 2009:

In thousands	2009	2008	2007
Asset retirement obligation liability at January 1,	$ 44,630	$ 42,092	$ 41,273
Asset retirement obligation accretion expense	2,250	2,053	1,962
Plus: Revisions	2,999	(117)	(1,817)
Additions for new assets	1,237	3,900	2,453
Less: Plugging costs and sold assets	(949)	(3,298)	(1,779)
Asset retirement obligation liability at December 31,	$ 50,167	$ 44,630	$ 42,092

As of December 31, 2009 and 2008, property and equipment included $33.8 million and $30.5 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 crude oil and natural gas properties are computed using the units of production method on a field basis based on total estimated proved developed crude 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 crude 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

Continental Resources, Inc. and Subsidiary

Notes to Consolidated Financial Statements (continued)

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 $47.1 million, $16.6 million and $13.2 million for 2009, 2008, and 2007 respectively.

The Company recognizes impairment expenses for developed crude oil and natural 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 crude oil and natural gas properties are reviewed for indicators of impairment on a field-by-field basis, resulting in the recognition of impairment provisions of $36.6 million, $12.3 million and $4.7 million, respectively, for 2009, 2008 and 2007. 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 revolving credit facility are capitalized and amortized over the term of the related debt using the straight-line basis, the use of which approximates the effective interest method. Costs incurred in issuance of the 8 1/4% Senior Notes due 2019 (Notes) were capitalized and amortized using the effective interest method, over the life of the Notes. The Company had capitalized costs of $10.8 million and $2.8 million (net of accumulated amortization of $7.8 million and $5.6 million) relating to the issuance of its long-term debt at December 31, 2009 and 2008, respectively. During the years ended December 31, 2009, 2008 and 2007, the Company recognized associated amortization expense of $2.2 million, $0.6 million and $0.6 million, respectively.

Derivatives

The Company is required to recognize 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 date. 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, derivative instruments 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.

Long-term debt consists of the revolving credit facility and the 8 1/4% Senior Notes due 2019 (Notes). The fair value of the revolving credit facility 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 the revolving credit facility is $226.0 million and $376.4 million at December 31, 2009 and 2008, respectively. The fair value of the Notes is based on quoted market prices and is $315.8 million at December 31, 2009.

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

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Continental Resources, Inc. and Subsidiary

Notes to Consolidated Financial Statements (continued)

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.

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.

The Company s policy is to recognize penalties and interest, if any, in income tax expense.

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 earnings per share computations for the years ended December 31, 2009, 2008 and 2007:

	2009	2008	2007
	In thousands, except per share data		
Income (numerator):			
Net income basic and diluted	$ 71,338	$ 320,950	$ 28,580
Weighted average shares (denominator):			
Weighted average shares basic	168,559	168,087	164,059
Restricted stock	562	686	211
Employee stock options	408	619	1,152
Weighted average shares diluted	169,529	169,392	165,422
Earnings per share:			
Basic	$ 0.42	$ 1.91	$ 0.17
Diluted	$ 0.42	$ 1.89	$ 0.17

New accounting standards

In December 2007, the Financial Accounting Standards Board (FASB) issued Accounting Standards Codification (ASC) 805-10 (formerly SFAS No. 141 (R)), *Business Combinations,* and ASC 810-10 (formerly SFAS No. 160), *Noncontrolling Interests in Consolidated Financial Statements, and amendment of ARB No. 51,* which changes how business acquisitions are accounted for and impacts financial statements both on the acquisition date and in subsequent periods. There are also changes in the accounting and reporting for minority interests, which are re-characterized as noncontrolling interests and classified as a component of equity. Both of these standards are effective for the Company for the year ended December 31, 2009. ASC 805-10 will be applied prospectively while ASC 810-10 requires retroactive adoption of the presentation and disclosure requirements for existing minority interests. All other requirements will be applied prospectively. The adoption of these standards did not have any impact on the Company s financial position or results of operations though it would impact financial reporting for any future acquisitions.

Continental Resources, Inc. and Subsidiary

Notes to Consolidated Financial Statements (continued)

In February 2008, the FASB issued ASC 820-10 (formerly Financial Staff Position SFAS 157-2), *Effective Date of FASB Statement No. 157,* which provided a one year delay of the effective date of ASC 820-10 (formerly SFAS 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). Beginning January 1, 2009, the Company applied the provisions of the standard to non-financial assets and liabilities. The standard applies to the Company s non-financial assets and liabilities in calculating fair value related to impairments of long-lived assets and asset retirement obligations. In both cases, the standard had no effect on these calculations. Both calculations are based primarily on level three inputs. The adoption of the standard on January 1, 2009 did not have a material impact on the Company s financial position or results of operations although the required disclosures have been made in *Notes to Consolidated Financial Statements Note 5, Derivative Instruments*.

In March 2008, the FASB issued ASC 815-10 (formerly SFAS No. 161), *Disclosures about Derivative Instruments and Hedging Activities,* which amends and expands disclosure requirements 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. The Company adopted the disclosure requirements of the standard beginning January 1, 2009 and it did not have an impact on the Company s financial position or results of operations.

In April 2009, the FASB issued additional application guidance and enhancements to disclosures regarding fair value measurements and impairments of securities.

ASC 820-10 (formerly FASB Staff Position (FSP) No. FAS 157-4), *Determining Fair Value When the Volume and Level of Activity for the Asset or Liability Have Significantly Decreased and Identifying Transactions That Are Not Orderly,* provides guidelines for making fair value measurements more consistent. It also includes guidance on identifying circumstances that indicate a transaction is not orderly. The Company adopted this FSP for the period ended June 30, 2009 and the adoption did not have an impact on its financial position or results of operations.

ASC 825-10 (formerly FSP No. FAS 107-1 and APB 28-1), *Interim Disclosures about Fair Value of Financial Instruments*, requires that disclosures concerning the fair value of financial instruments be presented in interim as well as annual financial statements, which enhances consistency in financial reporting. The Company adopted the provisions for the period ended June 30, 2009 and the adoption did not have an impact on its financial position or results of operations.

In May 2009, the FASB issued ASC 855-10 (formerly SFAS No. 165), *Subsequent Events* which establishes general standards of accounting for and disclosure of events that occur after the balance sheet date but before financial statements are issued or are available to be issued. Although there is new terminology, the standard is based on the same principles as those that previously existed. This statement, which includes a new required disclosure of the date through which an entity has evaluated subsequent events, is effective for interim or annual periods ending after June 15, 2009. The Company adopted the standard for the period ending June 30, 2009 and the adoption did not have an impact on its financial position or results of operations.

In June 2009, the FASB issued ASC 105-10 (formerly SFAS No. 168), *Accounting Standards Codification™ and the Hierarchy of Generally Accepted Accounting Principles.* The FASB Accounting Standards Codification™ (Codification) has become the source of authoritative U.S. GAAP recognized by the FASB to be applied by nongovernmental entities. Rules and interpretive releases of the SEC under authority of federal securities laws are also sources of authoritative GAAP for SEC registrants. All existing accounting standard documents are superseded by the Codification. All other non-grandfathered non-SEC accounting

Continental Resources, Inc. and Subsidiary

Notes to Consolidated Financial Statements (continued)

literature not included in the Codification will become non-authoritative. The Codification is effective for financial statements issued for interim and annual periods ending after September 15, 2009. The Codification does not change or alter existing GAAP and, therefore, did not have an impact on our financial position, results of operations, cash flows or disclosures.

On December 31, 2008, SEC issued Release No. 33-8995, *Modernization of Oil and Gas Reporting*. Release 33-8995 adopts revisions to the SEC s oil and gas reporting disclosure requirements and is effective for annual reports on Forms 10-K for years ending on or after December 31, 2009. The revisions are intended to provide investors with a more meaningful and comprehensive understanding of oil and gas reserves to help investors evaluate their investments in oil and gas companies. The amendments are also designed to modernize the oil and gas disclosure requirements to align them with current practices and changes in technology. Revised requirements in Release 33-8995 include, but are not limited to:

- Oil and gas reserves must be reported using the unweighted arithmetic average of the first day of the month prices for each month within the preceding 12 month period, rather than year-end prices;

- Companies will be allowed to report, on an optional basis, probable and possible reserves;

- Companies will be permitted to use new technologies to determine proved reserves, as long as those technologies have been demonstrated empirically to lead to reliable conclusions with respect to reserve volumes;

- Companies will be required to disclose, in narrative form, additional details about their proved undeveloped reserves (PUDs), including the total quantity of PUDs at year end, any material changes to PUDs that occurred during the year, investments and progress made to convert PUDs to developed oil and gas reserves and an explanation of the reasons why material concentrations of PUDs in individual fields or countries have remained undeveloped for five years or more after disclosure as PUDs; and

- Companies will be required to report the qualifications and measures taken to assure the independence and objectivity of any business entity or employee primarily responsible for preparing or auditing the reserves estimates.

In October 2009, the SEC issued Staff Accounting Bulletin No. 113 (SAB No. 113), which revises portions of the interpretive guidance included in the section of the Staff Accounting Bulletin Series titled *Topic 12: Oil and Gas Producing Activities* (Topic 12). The principal changes involve revisions to bring Topic 12 into conformity with the contents of Release 33-8995.

We adopted the provisions of the amendments on *Modernization of Oil and Gas Reporting* for the year ended December 31, 2009. It increased the disclosures about the Company s reserves; it changed the definition of proved reserves and changed the pricing assumptions. For a discussion of the impact of these provisions, please see *Note 15. Supplemental Crude Oil and Natural Gas Information (unaudited)*.

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Continental Resources, Inc. and Subsidiary

Notes to Consolidated Financial Statements (continued)

2. Cash Flow Information

Net cash provided by operating activities reflects cash payments as follows:

	December 31, 2009	2008	2007
		In thousands	
Interest paid	$ 14,562	$ 10,224	$ 11,499
Income taxes paid (refunded)	(21,894)	31,560	6,988

Noncash investing and financing activities are as follows:

	December 31, 2009	2008	2007
		In thousands	
Asset retirement obligations	$ 4,236	$ 3,783	$ 636

3. Property, Plant, and Equipment

Property, plant, and equipment include the following at December 31, 2009 and 2008:

	December 31, 2009	2008
	In thousands	
Proved crude oil and natural gas properties	$ 2,592,712	$ 2,250,757
Unproved crude oil and natural gas properties	271,910	248,689
Service properties, equipment and other	50,493	42,720
Total property and equipment	2,915,115	2,542,166
Accumulated depreciation, depletion and amortization	(847,060)	(607,023)
Net property and equipment	$ 2,068,055	$ 1,935,143

4. Accrued Liabilities and Other

Accrued liabilities and other includes the following at December 31, 2009 and 2008:

	December 31, 2009	2008
	In thousands	
Prepaid drilling costs	$ 13,475	$ 14,742
Accrued compensation	6,837	6,057
Accrued production and advalorem taxes	13,902	10,532
Accrued interest	7,736	2,112

Other	7,651	1,326
	$ 49,601	$ 34,769

Continental Resources, Inc. and Subsidiary

Notes to Consolidated Financial Statements (continued)

5. Derivative Instruments

The Company is required to recognize 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 and as a result marked its derivative instruments to fair value and recognized the realized and unrealized change in fair value on derivative instruments in the statements of income under the caption Loss on mark-to-market derivative instruments.

We have utilized swap and collar derivative contracts to hedge against the variability in cash flows associated with the forecasted sale of our future oil and gas production. While the use of these derivative instruments limits the downside risk of adverse price movements, their use also may limit future revenues from favorable price movements.

With respect to a swap contract, the counterparty is required to make a payment to us if the settlement price for any settlement period is less than the swap price, and we are required to make payment to the counterparty if the settlement price for any settlement period is greater than the swap price. For a collar contract, the counterparty is required to make a payment to us if the settlement price for any settlement period is below the floor price, we are required to make payment to the counterparty if the settlement price for any settlement period is above the ceiling price and neither party is required to make a payment to the other party if the settlement price for any settlement period is equal to or greater than the floor price and equal to or less than the ceiling price.

All of our derivative contracts are carried at their fair value on our consolidated balance sheet under the captions Receivables, joint interest and other, net and Accrued liabilities and other. Substantially all of our oil and gas derivative contracts are settled based upon reported prices on the NYMEX. The estimated fair value of these contracts is based upon various factors, including closing exchange prices on the NYMEX, over-the-counter quotations, and, in the case of collars, volatility and the time value of options. The calculation of the fair value of collars requires the use of an option-pricing model. See *Note 6. Fair Value Measurements*.

At December 31, 2009, we had outstanding contracts with respect to our future production as set forth in the tables below.

Crude Oil

			Collars			
		Swaps	Floors		Ceilings	
Period and Type of Contract	**Volume in MBbls**	**Weighted Average**	**Range**	**Weighted Average**	**Range**	**Weighted Average**
January 2010 June 2010						
Swaps	905	$ 80.50				
Collars	453		$ 70.00	$ 70.00	$ 95.00	$ 95.00
July 2010 December 2010						
Collars	644		75.00	75.00	96.75	96.75
January 2011 December 2011						
Collars	1,278		75.00	75.00	89.00	89.00

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Continental Resources, Inc. and Subsidiary

Notes to Consolidated Financial Statements (continued)

Natural Gas

Period and Type of Contract	Volume in MMMBtus	Swaps Weighted Average
January 2010 March 2010		
Swaps	2,700	$ 6.18
April 2010 June 2010		
Swaps	2,710	6.18
July 2010 September 2010		
Swaps	2,720	6.18
October 2010 December 2010		
Swaps	2,720	6.18

Natural Gas Basis Centerpoint East

Period and Type of Contract	Volume in MMMBtus	Swaps Weighted Average
January 2010 December 2010		
Swaps	7,200	$ (0.62)

Derivative Fair Value Income (Loss)

The following table presents information about the components of derivative fair value loss for the following periods presented:

	Year ended December 31, 2009	2008	2007
		In thousands	
Realized gain (loss) on derivatives:			
Crude oil	$	$ (34,669)	$ (18,166)
Natural gas	569		
Unrealized gain (loss) on derivatives			
Crude oil	(3,697)	26,703	(26,703)
Natural gas	4,205		
Natural gas basis	(2,597)		
Derivative fair value loss	$ (1,520)	$ (7,966)	$ (44,869)

The table below provides data about the carrying values of derivatives that are not accounted for using hedge accounting. The Company did not have any derivative assets or liabilities at December 31, 2008.

	December 31, 2009 Assets	(Liabilities)	Net

	Carrying Value	Carrying Value In thousands	Carrying Value
Derivatives that are not accounted for using hedge accounting:			
Crude oil	$ 610	$ (4,307)	$ (3,697)
Natural gas	1,608		1,608
	$ 2,218	$ (4,307)	$ (2,089)

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Continental Resources, Inc. and Subsidiary

Notes to Consolidated Financial Statements (continued)

6. Fair Value Measurements

The Company is required to calculate fair value based on a hierarchy which prioritizes the input to valuation techniques used to measure fair value into three levels. The fair value hierarchy gives the highest priority to quoted market prices (unadjusted) in active markets for identical assets or liabilities (Level 1) and the lowest priority to unobservable inputs (Level 3). Level 2 inputs are inputs, other than quoted prices included within Level 1, which are observable for the asset or liability, either directly or indirectly. The Company uses Level 1 inputs when available as Level 1 inputs generally provide the most reliable evidence of fair value.

Assets and Liabilities Measured at Fair Value on a Recurring Basis

Certain assets and liabilities are reported at fair value on a recurring basis. The Company s 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. In determining the fair value of our fixed price and basis swaps, due to the unavailability of relevant comparable market data for our exact contracts, a discounted cash flow method is used. The discounted cash flow method estimates future cash flows based on quoted market prices for future commodity prices, observable inputs relating to basis differentials and a risk-adjusted discount rate. The fair value of fixed price and basis swap derivatives is calculated using mainly significant observable inputs (Level 2). The calculation of the fair value of our collar contracts requires the use of an option-pricing model with significant unobservable inputs (Level 3). The valuation models for derivative contracts are primarily industry-standard models that consider various inputs including: (a) quoted forward prices for commodities, (b) time value, (c) volatility factors, and (d) current market and contractual prices for the underlying instruments, as well as other relevant economic measures. The Company s calculation for all trades is then compared to the counterparty valuation for reasonableness. The following table summarizes the valuation of investments and financial instruments by pricing levels that were accounted for at fair value on a recurring basis as of December 31, 2009:

Description	Fair value measurements using Level 1	Level 2	Level 3	Total
		In thousands		
Derivatives:				
Fixed price swaps	$	$ 3,783	$	$ 3,783
Basis swaps		(2,597)		(2,597)
Collars			(3,275)	(3,275)

The following table sets forth a reconciliation of changes in the fair value of financial assets and liabilities classified as Level 3 in the fair value hierarchy for the indicated periods:

	2009 In thousands
Balance at January 1, 2009	$
Total realized or unrealized gains (losses):	
Included in earnings	(3,275)
Included in other comprehensive income (loss)	
Purchases, issuances and settlements	
Transfers in and out of Level 3	
Balance at December 31, 2009	$ (3,275)
Change in unrealized gains (losses) relating to derivatives still held at December 31, 2009	$ (3,275)

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Notes to Consolidated Financial Statements (continued)

Financial Instruments not Recorded at Fair Value

The following table sets forth the fair value of financial instruments that are not recorded at fair value in our Consolidated Financial Statements.

	December 31, 2009		December 31, 2008	
	Carrying Amount	Fair Value	Carrying Amount	Fair Value
	In thousands			
Revolving credit facility	$ 226,000	$ 226,000	$ 376,400	$ 376,400
8 1/4% Senior Notes due 2019	297,524	315,750		

The fair value of the revolving credit facility approximates its carrying value based on the borrowing rates currently available to the Company for bank loans with similar terms and maturities. The fair value of the Notes is based on quoted market prices.

Assets and Liabilities Measured at Fair Value on a Nonrecurring Basis

Certain assets and liabilities are reported at fair value on a nonrecurring basis in the consolidated balance sheets. The following methods and assumptions were used to estimate the fair values.

Asset Impairments Proved crude oil and natural gas properties are reviewed for impairment when events and circumstances indicate a possible decline in the recoverability of the carrying value of such property. The estimated future cash flows expected in connection with the property are compared to the carrying amount of the property to determine if the carrying amount is recoverable. If the carrying amount of the property exceeds its estimated undiscounted future cash flows, the carrying amount of the property is reduced to its estimated fair value. Due to the unavailability of relevant comparable market data, a discounted cash flow method is used. The discounted cash flow method estimates future cash flows based on management s expectations for the future and includes estimates of future crude oil and natural gas production, commodity prices based on commodity futures price strips, operating and development costs, and a risk-adjusted discount rate. The fair value of crude oil and natural gas properties is calculated using significant unobservable inputs (Level 3).

As a result of changes in reserves and the forward futures price strip, developed crude oil and natural gas properties were reviewed for impairment at December 31, 2009 and the Company determined that the carrying amount of certain fields were not recoverable from future cash flows and, therefore, were impaired. The affected fields had a fair value of $0.8 million at December 31, 2009 resulting in $0.5 million of developed property impairments for the quarter ended December 31, 2009. A similar calculation at June 30, 2009, determined that the carrying amount of certain fields were not recoverable from future cash flows and, therefore, were impaired. The affected fields had a fair value of $1.8 million at June 30, 2009 resulting in $10.1 million of developed property impairments for the quarter ended June 30, 2009. A similar calculation at March 31, 2009 determined that the carrying amount of certain fields was not recoverable from future cash flows and, therefore, was impaired. The affected fields at March 31, 2009 had a fair value of $13.1 million resulting in $26.0 million of developed property impairments for first quarter of 2009. Total pre-tax (non-cash) impairments related to developed crude oil and natural gas properties were $36.6 million for the twelve months ended December 31, 2009.

Asset Retirement Obligations The fair value of asset retirement obligations (AROs) is estimated based on discounted cash flow projections using numerous estimates, assumptions and judgments regarding such factors as the existence of a legal obligation for an ARO; estimated probabilities, amounts and timing of settlements; the credit-adjusted risk-free rate to be used; and inflation rates. The fair value of ARO additions for the year ended December 31, 2009 was $1.2 million. The fair value of ARO is calculated using significant unobservable inputs (Level 3).

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Notes to Consolidated Financial Statements (continued)

7. Long-term Debt

Long-term debt consists of the following:

	December 31, 2009	December 31, 2008
	In thousands	
Revolving credit facility:		
Prime rate based loans	$	$
LIBOR based loans	226,000	376,400
Total revolving credit facility	226,000	376,400
8 1/4% Senior Notes due 2019(1)	297,524	
Total debt	$ 523,524	$ 376,400

(1) This amount includes the discount included in long-term debt of ($2.5) million.

Revolving credit facility The Company had $226.0 million and $376.4 million in long-term debt outstanding at December 31, 2009 and 2008, respectively, on its revolving credit facility due April 11, 2011. Borrowings under the facility bear interest, payable quarterly, at a rate per annum equal to the London Interbank Offered Rate (LIBOR) for one, two, three or six months, as elected by the Company, plus a margin ranging from 175 to 250 basis points, depending on the percentage of its borrowing base utilized, or the lead bank s reference rate (prime). The revolving credit facility has a maximum facility amount of $750.0 million and a borrowing base of $1.0 billion, subject to semi-annual re-determination. The commitment level was increased from $672.5 million to $750.0 million in June 2009. 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 amount subject to bank agreement. The Company s weighted average interest rate was 2.66% at December 31, 2009.

The Company had $523.4 million of unused commitments under the revolving credit facility at December 31, 2009 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 revolving credit facility) and a Total Funded Debt to EBITDAX, as such terms are defined in the credit agreement, of no greater than 3.75 to 1.0. The Company was in compliance with these covenants at December 31, 2009.

8 1/4% Senior Subordinated Notes due 2019 On September 23, 2009, the Company issued Notes. The Notes, which carry a coupon rate of 8.25%, were sold at a discount (99.16% of par), which equates to an effective yield to maturity of approximately 8.375%. The Company received net proceeds of approximately $289.7 million, after deducting the underwriters discounts of approximately $6.8 million and offering expenses of approximately $1.0 million. The net proceeds were used to repay a portion of the borrowings outstanding under our revolving credit facility.

The Notes will mature on October 1, 2019, and interest is payable on the Notes on each April 1 and October 1, commencing April 1, 2010. The Company has the option to redeem all or a portion of the Notes at any time on or after October 1, 2014 at the redemption price specified in the Indenture dated September 23, 2009 (the Indenture) plus accrued and unpaid interest. The Company may also redeem the Notes, in whole or in part, at a make-whole redemption price specified in the Indenture, plus accrued and unpaid interest, at any time prior to October 1, 2014. In addition, the Company may redeem up to 35% of the Notes prior to October 1, 2012 under certain circumstances with the net cash proceeds from certain equity offerings. The Indenture contains certain

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Notes to Consolidated Financial Statements (continued)

restrictions on our ability to incur additional debt, pay dividends on our common stock, make investments, create liens on our assets, engage in transactions with our affiliates, transfer or sell assets, consolidate or merge, or sell substantially all of our assets. These covenants are subject to a number of important exceptions and qualifications. The Company was in compliance with these covenants as of December 31, 2009. The Notes are not subject to any sinking fund requirements. Our subsidiary, which currently has no independent assets or operations, fully and unconditionally guarantees this debt.

Information Technology Financing Arrangement On August 21, 2009, the Company entered into a Project Financing Agreement with IBM Credit LLC pursuant to which IBM Credit may advance up to $10.0 million for information technology services and software products to be provided to us by International IBM. The financing agreement matures on September 30, 2013, is unsecured and the interest rate under the agreement is 4.73%. In December 2009, the Company paid the note in full and does not plan to take any additional advances in the future.

8. Income Taxes

The following is an analysis of the Company s income tax provision.

	Year ended December 31,		
	2009	2008	2007
		In thousands	
Current:			
Federal	$ 2,444	$ 13,465	$ 5,785
State	107		
Total current tax provision	2,551	13,465	5,785
Deferred:			
Federal	35,302	164,928	233,801
State	817	19,187	28,611
Total deferred tax provision	36,119	184,115	262,412
Income tax provision	$ 38,670	$ 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, 2009, 2008 and 2007.

	Year ended December 31,		
	2009	2008	2007
		In thousands	
Federal tax at statutory rate (35%)	$ 38,503	$ 181,486	$ 103,872
State income taxes, net of federal benefit	(108)	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	275	(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	$ 38,670	$ 197,580	$ 268,197

(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

Continental Resources, Inc. and Subsidiary

Notes to Consolidated Financial Statements (continued)

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, 2009 and 2008 are as follows:

	December 31, 2009	December 31, 2008
	In thousands	
Current:		
Deferred tax assets [(1)]		
Unrealized losses on derivatives	$ 794	$
Other expenses	788	715
Total current deferred tax assets	1,582	715
Noncurrent:		
Deferred tax assets		
Net operating loss carryforward	11,352	8,087
Alternative minimum tax carryforward	12,758	19,858
Other	2,421	958
Total noncurrent deferred tax assets	26,531	28,903
Deferred tax liabilities		
Property and equipment	515,390	473,387
Deferred compensation	382	1,268
Total noncurrent deferred tax liabilities	515,772	474,655
Net noncurrent deferred tax liabilities	489,241	445,752
Net deferred tax liabilities	$ 487,659	$ 445,037

(1) Deferred and prepaid taxes on the accompanying consolidated balance sheets contain receivables of $3.0 million and $18.1 million for overpaid taxes at December 31, 2009 and 2008, respectively.

As of December 31, 2009, the Company had a Federal net operating loss carryforward of $17.8 million which will expire beginning in 2028 and state net operating losses totaling $178,000 which have expiration periods that vary according to state jurisdiction. Included in the net operating loss carryforward is excess tax benefit related to stock compensation of $12.9 million ($4.9 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 $12.8 million and a statutory depletion carryforward, which will be recognized when realized, of $7.4 million, neither 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 2004. 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.

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Continental Resources, Inc. and Subsidiary

Notes to Consolidated Financial Statements (continued)

9. Lease Commitments

Lease expense associated with the Company s operating leases for the years ended December 31, 2009, 2008 and 2007, was $1.6 million, $6.0 million and $6.0 million, respectively. At December 31, 2009, including leases renewed and entered into subsequent to December 31, 2009, 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 these years	Leases with related parties	Leases with unrelated parties in thousands	Total amount
2010	$ 1,537	$ 111	$ 1,648
2011	365	71	436
2012		52	52
2013		49	49
2014		43	43
Total obligations	$ 1,902	$ 326	$ 2,228

The Company leases compressors from a related party for approximately $400,000 per month under an operating lease with the related party furnishing all labor, lubricants and supplies, and the Company paying for the electric power. The primary term of the operating lease expired on January 28, 2009 and continued on a month-to-month basis through 2009. A new agreement has been negotiated effective February 1, 2010 for a term of 16 months resulting in the monthly lease fee being reduced to $50,000 and Continental assuming 100% of the labor, lubricants and supplies, which previously had been covered under the old lease agreement. The Company leases office space under operating leases from the principal shareholder as explained in *Note 11. Related Party Transactions*.

10. Commitments and Contingencies

Drilling Commitments. As of December 31, 2009, the Company had one drilling rig contract that expires in August 2011. This commitment is not recorded in the accompanying consolidated balance sheets. Future commitments as of December 31, 2009 are $14.6 million.

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 2009, 2008 and 2007, contributions to the plan were 5% of eligible employees compensation, excluding bonuses. Expense for the years ended December 31, 2009, 2008 and 2007, was $1.3 million, $1.1 million and $0.9 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, 2009 and 2008, the accrued liability for health and worker s compensation claims was $1.3 million and $873,000, 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 operations of the Company. As of December 31, 2009 and 2008, the Company has provided a reserve of $2.7

Continental Resources, Inc. and Subsidiary

Notes to Consolidated Financial Statements (continued)

million and $1.2 million, respectively, for various matters none of which are believed to be individually significant.

Environmental Risk. Due to the nature of the crude oil and natural 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. During the years ended December 31, 2009, 2008, and 2007, these sales were approximately $26.6 million, $64.7 million, and $33.9 million. The Company also contracts for field services such as compression and drilling rig services and purchases residue fuel gas and reclaimed crude oil from certain affiliates. Production expense attributable to these affiliates was $16.5 million, $20.7 million and $18.9 million for the years ended December 31, 2009, 2008 and 2007, respectively. The total amount paid to these companies, a portion of which was billed to other interest owners, was approximately $90.4 million, $104.1 million and $76.3 million during the years ended December 31, 2009, 2008 and 2007, respectively. The Company also received $428,000 from an affiliate for saltwater disposal fees. 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 $82,000 and $332,000 during 2009 and 2008, respectively. At December 31, 2009 and 2008, approximately $7.8 million and $14.9 million were due from affiliates and approximately $9.6 million and $25.7 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 $11.3 million, $16.7 million, and $10.4 million and billed expenses of $15.9 million, $14.2 million, and $9.1 million during the years ended December 31, 2009, 2008, and 2007, respectively, to these affiliates. The Company also paid to these affiliates $508,000 in 2009 and $157,000 in 2008 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 $921,000, $804,000 and $707,000 for the years ended December 31, 2009, 2008 and 2007, respectively. The term of the lease is through February 2011 at an annual rate of approximately $988,000.

Under a contract for natural gas sales to an affiliate the Company pays for gathering and treating fees which amounted to $4.5 million in 2009 and $1.0 million in 2008.

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.

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

Continental Resources, Inc. and Subsidiary

Notes to Consolidated Financial Statements (continued)

$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 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. 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.

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 2009 and 2008, the Company paid cash dividends of $41,000 and $207,000, respectively, upon vesting of restricted stock granted prior to dividend declaration in 2007.

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 $11.4 million, $9.1 million and $12.8 million during 2009, 2008 and 2007, respectively.

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, 2009, options covering 2,001,473 shares had been exercised and 478,496 had been cancelled.

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Notes to Consolidated Financial Statements (continued)

The Company s stock option activity under the 2000 Plan from December 31, 2006 to December 31, 2009 was as follows:

	Outstanding		Exercisable	
	Number of options	Weighted average exercise price	Number of options	Weighted average exercise price
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
Exercised	(138,010)	1.78		
Outstanding December 31, 2009	312,190	1.06	312,190	1.06

The total intrinsic value of options exercised during the years ended December 31, 2009, 2008 and 2007 was $5.3 million, $15.1 million and $11.1 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, 2009, all options were exercisable and had a weighted average life of 1.31 years with an aggregate intrinsic value of $13.1 million.

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 year ended December 31, 2007 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.

The following table summarizes information about stock options outstanding at December 31, 2009:

	Options Outstanding			Options Exercisable	
Exercise Prices	Number Outstanding	Weighted Average Remaining Contractual Life	Weighted Average Exercise Price	Number Exercisable at 12/31/09	Weighted-Average Exercise Price
$1.27	194,750	0.75 years	$ 1.27	194,750	$ 1.27
0.71	117,440	2.25 years	0.71	117,440	0.71
	312,190		1.06	312,190	1.06

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, 2009, the Company had 3,291,186 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, 2006 to December 31, 2009, is presented below:

	Number of non-vested shares	Weighted average grant-date fair value
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
Granted	411,217	28.94
Vested	(369,784)	22.00
Forfeited	(25,504)	21.98
Non-vested restricted shares at December 31, 2009	1,126,821	26.55

The fair value of the restricted shares that vested during 2009, 2008 and 2007 at their vesting date was $13.3 million $11.1 million and $4.3 million, respectively. As of December 31, 2009, there was $19.3 million of unrecognized compensation expense related to non-vested restricted shares. The expense is expected to be recognized over a weighted average period of 1.6 years.

Continental Resources, Inc. and Subsidiary

Notes to Consolidated Financial Statements (continued)

14. Crude Oil and Natural Gas Property Information

The following table sets forth the Company s results of operations from crude oil and natural gas producing activities for the years ended December 31, 2009, 2008 and 2007. 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 below shows taxes for 2007 from May 14, 2007 to the end of the year at statutory rates and pro forma for the remaining periods.

	December 31,		
	2009	2008	2007
		In thousands	
Crude oil and natural gas sales	$ 610,698	$ 939,906	$ 606,514
Production expense and tax	(138,887)	(160,245)	(109,051)
Exploration expense	(12,615)	(40,160)	(9,163)
Depreciation, depletion, amortization and accretion	(207,602)	(148,902)	(91,678)
Property impairments	(83,694)	(28,847)	(17,879)
Income taxes	(63,802)	(213,466)	(102,676)
Results from crude oil and natural gas producing activities	$ 104,098	$ 348,286	$ 276,067
(The below information is unaudited)			
Pro forma presentation for income tax:			
Results from crude oil and natural gas producing activities before pro forma income tax			$ 378,743
Pro forma income tax			(143,922)
Results from pro forma crude oil and natural gas producing activities			$ 234,821

Costs incurred in crude oil and natural gas activities

Costs incurred, both capitalized and expensed, in connection with the Company s crude oil and natural gas acquisition, exploration and development activities for the three years ended December 31, 2009, 2008 and 2007 are shown below:

	Year Ended December 31,		
	2009	2008	2007
		In thousands	
Property Acquisition Costs:			
Proved	$ 1,217	$ 74,663	$ 4,166
Unproved	73,273	199,621	21,729
Total property acquisition costs	74,490	274,284	25,895
Exploration Costs	96,440	235,263	181,883
Development Costs	260,407	471,820	316,741
Total	$ 431,337	$ 981,367	$ 524,519

Exploration costs above include asset retirement costs of $368,000, $687,000 and $236,000 and development costs above include asset retirement costs of $859,000, $3,252,000 and $401,000 for the years 2009, 2008 and 2007, respectively.

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Notes to Consolidated Financial Statements (continued)

Aggregate capitalized costs

Aggregate capitalized costs relating to the Company s crude oil and natural gas producing activities, and related accumulated depreciation, depletion and amortization as of December 31, 2009 and 2008 are as follows:

	Year Ended December 31,	
	2009	2008
	In thousands	
Proved oil and natural gas properties	$ 2,592,712	$ 2,250,757
Unproved oil and natural gas properties	271,910	248,689
Total	2,864,622	2,499,446
Less-accumulated depreciation, depletion and amortization	(826,593)	(589,513)
Net capitalized costs	$ 2,038,029	$ 1,909,933

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 crude oil and natural 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 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:

	Year Ended December 31,		
	2009	2008	2007
		In thousands	
Balance, January 1,	$ 46,274	$ 32,936	$ 10,049
Additions to capitalized exploratory well costs pending determination of proved reserves	50,765	151,301	139,765
Reclassification to proved oil and natural gas properties based on the determination of proved reserves	(67,706)	(117,958)	(113,329)
Capitalized exploratory well costs charged to expense	(6,477)	(20,005)	(3,549)
Balance, December 31,	$ 22,856	$ 46,274	$ 32,936
Number of projects	20	56	45

15. Supplemental Crude Oil and Natural 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.

Continental Resources, Inc. and Subsidiary

Notes to Consolidated Financial Statements (continued)

prepared reserve estimates for properties comprising approximately 90% of the Company s standardized measure of discounted future net cash flows as of December 31, 2009 and 83% for 2008 and 2007. Remaining reserve estimates were prepared by the Company s technical staff. All reserves stated here are located in the United States of America. We adopted the provisions of the amendments on *Modernization of Oil and Gas Reporting* for the year ended December 31, 2009. It increased the disclosures about the Company s reserves; it changed the definition of proved reserves and changed the pricing assumptions.

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 crude oil and natural gas reserves. Crude oil and natural gas reserve engineering is a subjective process of estimating underground accumulations of crude 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 crude oil and natural gas that are ultimately recovered.

Natural gas imbalance receivables and liabilities for each of the three years ended December 31, 2009, 2008 and 2007, were not material and have not been included in the reserve estimates.

Proved crude oil and natural gas reserves

	Natural Gas (MMcf)	**Crude Oil (MBbls)**
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
Revisions of previous estimates	(2,485)	1,609
Extensions, discoveries and other additions	210,029	75,450
Production	(21,606)	(10,022)
Sale of minerals in place		
Purchase of minerals in place	4	4
Proved reserves as of December 31, 2009	504,080	173,280

Continental Resources, Inc. and Subsidiary

Notes to Consolidated Financial Statements (continued)

Revisions. Revisions represent changes in previous reserves estimates, either upward or downward, resulting from new information normally obtained from development drilling and production history or resulting from a change in economic factors, such as commodity prices, operating costs or development costs. December 31, 2008 revisions were primarily due to lower commodity prices at the end of 2008.

Reserves at December 31, 2009 were computed using the 12-month unweighted average of the first-day-of-the-month prices as required by the new SEC rules. However, had we been able to use December 31, 2009 prices as in previous years, our revisions for 2009 would have increased by an additional 4,070 MBoe.

Extensions, discoveries and other additions. These are additions to proved reserves that result from (1) extension of the proved acreage of previously discovered reservoirs through additional drilling in periods subsequent to discovery and (2) discovery of new fields with proved reserves or of new reservoirs of proved reserves in old fields. Extensions, discoveries and other additions at December 31, 2009 include increases in proved undeveloped locations as a result of the change in the SEC s rules to allow producers in continuous accumulation plays to report additional undrilled locations beyond one offset on each side of a horizontal producing well.

The increase in 2009 reserves described above had an effect on our depreciation, depletion and amortization, net income and earnings per share for the fourth quarter of 2009. Other than the effect the change in price methodology had on the reserves as discussed above, the Company is unable to estimate the effect of the remaining changes because a comparative reserve report prepared under the previous rules does not exist.

The following reserve information sets forth the estimated quantities of proved developed and proved undeveloped crude oil and natural gas reserves of the Company as of December 31, 2007, 2008 and 2009:

	Year ended December 31,	Natural Gas (MMcf)	Crude Oil (MBbls)	Crude Oil Equivalent (MBoe)
Proved Developed Reserves	2007	128,831	79,756	101,228
	2008	153,536	80,387	105,976
	2009	169,782	85,270	113,567
Proved Undeveloped Reserves	2007	53,988	24,389	33,387
	2008	164,602	25,852	53,286
	2009	334,298	88,010	143,726

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 crude oil equivalent using a conversion factor of six thousand cubic feet per barrel.

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

The standardized measure of discounted future net cash flows presented in the following table was computed using the unweighted average of first-day-of-the-month commodity prices over the preceding year for 2009 and year-end prices for 2008 and 2007, costs in effect at December 31, 2009 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 crude oil and natural 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)

	2009	December 31, 2008 In thousands	2007
Future cash inflows	$ 10,993,595	$ 5,777,441	$ 9,754,787
Future production costs	(3,190,748)	(1,993,888)	(2,427,862)
Future development and abandonment costs	(2,045,242)	(663,497)	(461,811)
Future income taxes	(1,268,119)	(703,329)	(2,008,293)
Future net cash flows	4,489,486	2,416,727	4,856,821
10% annual discount for estimated timing of cash flows	(2,647,946)	(1,139,626)	(2,274,482)
Standardized measure of discounted future net cash flows	$ 1,841,540	$ 1,277,101	$ 2,582,339

The weighted average crude oil price utilized in the computation of future cash inflows was $52.76, $39.69, and $82.86 per barrel at December 31, 2009, 2008 and 2007, respectively. The weighted average natural gas price utilized in the computation of future cash inflows was $3.67, $4.90, and $6.16 per Mcf at December 31, 2009, 2008 and 2007, 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.

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

	2009	December 31, 2008 In thousands	2007
Standardized measure of discounted future net cash flows at the beginning of the year	$ 1,277,101	$ 2,582,339	$ 1,584,472
Extensions, discoveries and improved recovery, less related costs	458,352	276,774	643,016
Revisions of previous quantity estimates	38,360	(169,605)	90,188
Changes in estimated future development and abandonment costs	23,136	(55,793)	(14,597)
Purchase (sales) of minerals in place	78	115,711	2,050
Net change in prices and production costs	417,739	(1,981,977)	1,313,657
Accretion of discount	127,710	258,234	158,447
Sales of oil and natural gas produced, net of production costs	(471,811)	(779,661)	(497,463)
Development costs incurred during the period	125,048	305,028	232,356
Change in timing of estimated future production and other	4,082	26,732	15,677
Change in income taxes	(158,255)	699,319	(945,464)
Net Change	564,439	(1,305,238)	997,867
Standardized measure of discounted future net cash flows at the end of the year	$ 1,841,540	$ 1,277,101	$ 2,582,339

Continental Resources, Inc. and Subsidiary

Notes to Consolidated Financial Statements (continued)

16. Quarterly Financial Data (Unaudited)

Our quarterly financial data for 2009 and 2008 is summarized below.

	Quarter			
	First	Second	Third	Fourth
	In thousands, except per share data			
2009				
Revenues	$ 96,608	$ 151,761	$ 170,204	$ 207,638
Operating (loss) income	$ (38,432)	$ 26,181	$ 59,286	$ 85,253
Net income (loss)	$ (26,613)	$ 13,508	$ 34,929	$ 49,514
Net income (loss) per share:				
Basic	$ (0.16)	$ 0.08	$ 0.21	$ 0.29
Diluted	$ (0.16)	$ 0.08	$ 0.21	$ 0.29
2008				
Revenues	$ 227,651	$ 303,434	$ 293,609	$ 135,796
Operating income	$ 141,693	$ 205,229	$ 171,159	$ 11,242
Net income	$ 87,971	$ 127,307	$ 105,256	$ 416
Net income per share:				
Basic	$ 0.52	$ 0.76	$ 0.63	$ 0.00
Diluted	$ 0.52	$ 0.75	$ 0.62	$ 0.00

Item 9. Changes in and Disagreements with Accountants on Accounting and Financial Disclosure

There have been no changes in accountants or any disagreements with accountants.

Item 9A. Controls and Procedures

Disclosure Controls and Procedures

Our Chief Executive Officer and Chief Financial Officer have reviewed and evaluated the effectiveness of our disclosure controls and procedures (as defined in Exchange Act Rule 240.13a-15(e) and 15d-15(e)) as of the end of the period covered by this report. Disclosure controls and procedures include, without limitation, controls and procedures designed to ensure that information required to be disclosed by an issuer in reports that it files or submits with this report accumulated and communicated to the issuer s management, including its Chief Executive Officer and Chief Financial Officer, or persons performing similar functions, as appropriate to make timely decisions regarding required disclosures and are designed to record, process, summarize and report such information within the time periods specified. Based on that evaluation, our Chief Executive Officer and our Chief Financial Officer have concluded that as of December 31, 2009, our disclosure controls and procedures were effective to ensure that information required to be disclosed by us in this report are recorded, processed, summarized and reported, within the time periods specified.

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Management s Report on Internal Control Over Financial Reporting

MANAGEMENT S REPORT ON INTERNAL CONTROL OVER FINANCIAL REPORTING

Our Company s management is responsible for establishing and maintaining adequate internal control over financial reporting, as such term is defined in Exchange Act Rule 13a-15(f). Internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of our financial statements for external purposes in accordance with generally accepted accounting principles. Under the supervision and with the participation of our Company s management, including the Chief Executive Officer and the Chief Financial Officer, we conducted an evaluation of the effectiveness of our internal control over financial reporting based on the framework in *Internal Control Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission.

Our internal control over financial reporting includes those policies and procedures that: (1) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of our assets; (2) provide reasonable assurance that transactions are recorded as necessary to permit preparation of our financial statements in accordance with generally accepted accounting principles, and that our receipts and expenditures are being made only in accordance with authorizations of our management and directors; and (3) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use or disposition of our assets that could have a material effect on our financial statements.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

Based on our evaluation under the framework in *Internal Control Integrated Framework,* the management of our Company concluded that our internal control over financial reporting was effective as of December 31, 2009.

The effectiveness of our internal control over financial reporting as of December 31, 2009 has been audited by Grant Thornton LLP, an independent registered public accounting firm, as stated in their report that follows.

Harold Hamm

Chief Executive Officer

John D. Hart

Senior Vice President, Chief Financial Officer and Treasurer

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

Board of Directors and Shareholders

Continental Resources, Inc.

We have audited Continental Resources, Inc. (an Oklahoma corporation) and Subsidiary s (the Company) internal control over financial reporting as of December 31, 2009, based on criteria established in *Internal Control Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). The Company s management is responsible for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting, included in the accompanying *Management s Report on Internal Control Over Financial Reporting*. Our responsibility is to express an opinion on the Company s internal control over financial reporting based on our audit.

We conducted our audit in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether effective internal control over financial reporting was maintained in all material respects. Our audit included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, testing and evaluating the design and operating effectiveness of internal control based on the assessed risk, and performing such other procedures as we considered necessary in the circumstances. We believe that our audit provides a reasonable basis for our opinion.

A company s internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company s internal control over financial reporting includes those policies and procedures that (1) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (2) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (3) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company s assets that could have a material effect on the financial statements.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

In our opinion, Continental Resources, Inc. and Subsidiary maintained, in all material respects, effective internal control over financial reporting as of December 31, 2009, based on criteria established in *Internal Control Integrated Framework* issued by COSO.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the consolidated balance sheets of Continental Resources, Inc. and Subsidiary as of December 31, 2009 and 2008, and the related consolidated statements of income, shareholders equity and cash flows for each of the three years in the period ended December 31, 2009 and our report dated February 26, 2010, expressed an unqualified opinion.

/s/ GRANT THORNTON LLP

Oklahoma City, Oklahoma

February 26, 2010

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Changes in Internal Control over Financial Reporting

As of the end of the period covered by this report, we carried out an evaluation, under the supervision and with the participation of our Chief Executive Officer and Chief Financial Officer, of our internal control over financial reporting to determine whether any changes occurred during the fourth quarter of 2009 that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting. Based on that evaluation, there were no changes in our internal control over financial reporting or in other factors that have materially affected or are reasonably likely to materially affect our internal control over financial reporting.

Item 9B. Other Information

None.

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PART III

Item 10. Directors, Executive Officers and Corporate Governance

Information as to Item 10 will be set forth in the Proxy Statement for the Annual Meeting of Shareholders to be held in 2010, (the Annual Meeting) and is incorporated herein by reference.

Item 11. Executive Compensation

Information as to Item 11 will be set forth in the Proxy Statement for the Annual Meeting and is incorporated herein by reference.

Item 12. Security Ownership of Certain Beneficial Owners and Management and Related Stockholder Matters

Information as to Item 12 will be set forth in the Proxy Statement for the Annual Meeting and is incorporated herein by reference.

Item 13. Certain Relationships and Related Transactions

The information as to Item 13 will be set forth in the Proxy Statement for the Annual Meeting and is incorporated herein by reference.

Item 14. Principal Accountant Fees and Services

The information as to Item 14 will be set forth in the Proxy Statement for the Annual Meeting and is incorporated herein by reference.

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PART IV

Item 15. Exhibits and Financial Statement Schedules

(1) *Financial Statements*

The Consolidated Financial Statements of Continental Resources, Inc. and the Report of the Independent Registered Public Accounting Firm are included in Item 8 of this report beginning on page 63.

(2) *Financial Statement Schedules*

None.

(3) *Index to Exhibits*

The exhibits marked with the asterisk symbol (*) are filed or furnished (in the case of Exhibits 32 and 99) with this Form 10-K. The exhibits marked with the cross symbol ( ) are management contracts or compensatory plans or arrangements filed pursuant to Item 601(b)(10)(iii) of Regulation S-K.

3.1	Third Amended and Restated Certificate of Incorporation of Continental Resources, Inc. filed as Exhibit 3.1 to the Company s Current Report on Form 8-K (Commission File No. 001-328861) filed May 22, 2007 and incorporated herein by reference.
3.2	Second Amended and Restated Bylaws of Continental Resources, Inc. filed as Exhibit 3.2 to the Company s Current Report on Form 8-K (Commission File No. 001-328861) filed May 22, 2007 and incorporated herein by reference.
4.1	Registration Rights Agreement filed as Exhibit 10.1 to the Company s Current Report on Form 8-K (Commission File No. 001-328861) filed May 22, 2007 and incorporated herein by reference.
4.2	Specimen Common Stock Certificate filed as Exhibit 4.1 to the Company s registration statement on Form S-1 (Commission File No. 333-132257) filed April 14, 2006 and incorporated herein by reference.
4.3	Indenture dated as of September 23, 2009 among Continental Resources, Inc., Banner Pipeline Company, L.L.C. and Wilmington Trust FSB, as trustee, filed as Exhibit 4.1 to the Company s Current Report on Form 8-K (Commission File No. 001-32886) filed September 24, 2009 and incorporated herein by reference.
4.4	Registration Rights Agreement dated as of September 23, 2009 among Continental Resources, Inc., Banner Pipeline Company, L.L.C. and the Initial Purchasers named therein, filed as Exhibit 4.2 to the Company s Current Report on Form 8-K (Commission File No. 001-32886) filed September 24, 2009 and incorporated herein by reference.
10.1	Sixth Amended and Restated Credit Agreement among Union Bank of California, N.A., Guaranty Bank, FSB, Fortis Capital Corp., The Royal Bank of Scotland plc, other financial institutions and banks and Continental Resources, Inc. dated April 12, 2006 filed as Exhibit 10.1 to the Company s registration statement on Form S-1 (Commission File No. 333-132257) filed April 14, 2006 and incorporated herein by reference.
10.2	Omnibus Agreement among Continental Resources, Inc., Hiland Partners, LLC, Harold Hamm, Hiland Partners GP, LLC, Continental Gas Holdings, Inc. and Hiland Partners, LP effective as of the closing of Hiland Partners, LP s initial public offering of common units on October 22, 2004 (incorporated by reference to Exhibit 10.10 to the Annual Report on Form 10-K of Hiland Partners, LP filed on March 30, 2005, Commission File No. 000-51120).

10.3	Compression Services Agreement among Hiland Partners, LP and Continental Resources, Inc. effective as of January 28, 2005 (incorporated by reference to Exhibit 10.3 to the Annual Report on Form 10-K of Hiland Partners, LP filed on March 30, 2005, Commission File No. 000-51120).
10.4	Gas Purchase Contract between Continental Resources, Inc. and Hiland Partners, LP dated November 8, 2005 (incorporated by reference to Exhibit 10.1 to the Current Report on Form 8-K of Hiland Partners, LP filed on November 10, 2005, Commission File No. 000-51120).
10.5	Strategic Customer Relationship Agreement among Complete Energy Services, Inc., CES Mid-Continent Hamm, Inc. and Continental Resources, Inc. dated October 14, 2004 (incorporated by reference to Exhibit 10.12 to the Registration Statement on Form S-1 of Complete Production Services, Inc. filed on November 15, 2005, Commission File No. 333-128750).
10.6	Continental Resources, Inc. 2000 Stock Option Plan filed as Exhibit 10.6 to the Company s registration statement on Form S-1 (Commission File No. 333-132257) filed April 14, 2006 and incorporated herein by reference.
10.7	First Amendment to Continental Resources, Inc. 2000 Stock Option Plan filed as Exhibit 10.7 to the Company s registration statement on Form S-1 (Commission File No. 333-132257) filed April 14, 2006 and incorporated herein by reference.
10.8	Form of Incentive Stock Option Agreement filed as Exhibit 10.8 to the Company s registration statement on Form S-1 (Commission File No. 333-132257) filed April 14, 2006 and incorporated herein by reference.
10.9	Amended and Restated Continental Resources, Inc. 2005 Long-Term Incentive Plan effective as of April 3, 2006 filed as Exhibit 10.9 to the Company s registration statement on Form S-1 (Commission File No. 333-132257) filed April 14, 2006 and incorporated herein by reference.
10.10	Form of Restricted Stock Award Agreement filed as Exhibit 10.10 to the Company s registration statement on Form S-1 (Commission File No. 333-132257) filed April 14, 2006 and incorporated herein by reference.
10.11	Amended and Restated Employment Agreement between Continental Resources, Inc. and Mark E. Monroe dated April 3, 2006 filed as Exhibit 10.11 to the Company s registration statement on Form S-1 (Commission File No. 333-132257) filed April 14, 2006 and incorporated herein by reference.
10.12	Form of Indemnification Agreement between Continental Resources, Inc. and each of the directors and executive officers thereof filed as Exhibit 10.12 to the Company s registration statement on Form S-1 (Commission File No. 333-132257) filed April 14, 2006 and incorporated herein by reference.
10.13	Membership Interest Assignment Agreement by and between Continental Resources, Inc., the Harold Hamm Revocable Inter Vivos Trust, the Harold Hamm HJ Trust and the Harold Hamm DST Trust dated March 30, 2006 filed as Exhibit 10.13 to the Company s registration statement on Form S-1 (Commission File No. 333-132257) filed April 14, 2006 and incorporated herein by reference.
10.14	Crude oil gathering agreement between Banner Pipeline Company, L.L.C., a wholly owned subsidiary of Continental Resources, Inc. and Banner Transportation Company dated July 11, 2007 filed as Exhibit 99.1 to the Company s Current Report on Form 8-K (Commission File No. 001-328861) filed July 11, 2007 and incorporated herein by reference.
10.15	Amendment No. 1 Dated as of April 17, 2007 to the Sixth Amended and Restated Credit Agreement filed as Exhibit 10.15 to the Company s Form 10-K for the year ended December 31, 2008 (Commission File No. 001-32886) filed February 27, 2009 and incorporated herein by reference.

10.16	Commitment Increase Agreement and Amendment No. 2 Dated as of January 23, 2008 to the Sixth Amended and Restated Credit Agreement filed as Exhibit 10.16 to the Company s Form 10-K for the year ended December 31, 2008 (Commission File No. 001-32886) filed February 27, 2009 and incorporated herein by reference.
10.17	Amendment No. 3 Dated as of December 22, 2008, to the Sixth Amended and Restated Credit Agreement filed as Exhibit 10.17 to the Company s Form 10-K for the year ended December 31, 2008 (Commission File No. 001-32886) filed February 27, 2009 and incorporated herein by reference.
10.18	Commitment Increase Agreement and Amendment No. 4 Dated as of December 23, 2008 to the Sixth Amended and Restated Credit Agreement filed as Exhibit 10.18 to the Company s Form 10-K for the year ended December 31, 2008 (Commission File No. 001-32886) filed February 27, 2009 and incorporated herein by reference.
10.19	Summary of Non-Employee Director Compensation filed as Exhibit 10.19 to the Company s Form 10-K for the year ended December 31, 2008 (Commission File No. 001-32886) filed February 27, 2009 and incorporated herein by reference.
10.20	Purchase Agreement dated as of September 18, 2009 among Continental Resources, Inc., Banner Pipeline Company, L.L.C. and the Initial Purchasers named therein, filed as Exhibit 10.2 to the Company s Current Report on Form 8-K (Commission File No. 001-32886) filed September 24, 2009 and incorporated herein by reference.
21.1*	Subsidiaries of Continental Resources, Inc.
23.1*	Consent of Grant Thornton LLP.
23.2*	Consent of Ryder Scott Company, L.P.
31.1*	Certification of the Company s Chief Executive Officer Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002 (18 U.S.C. Section 7241)
31.2*	Certification of the Company s Chief Financial Officer Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002 (18 U.S.C. Section 7241)
32*	Certification of the Company s Chief Executive Officer and Chief Financial Officer Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002 (18 U.S.C. Section 1350)
99.1*	Report of Ryder Scott Company, L. P., Independent Petroleum Engineers and Geologists

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Signatures

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

CONTINENTAL RESOURCES, INC.

By:	/s/ Harold G. Hamm
Name:	**Harold G. Hamm**
Title:	**Chief Executive Officer**
Date:	**February 26, 2010**

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed by the following persons on behalf of Continental Resources, Inc. in the capacities and on the dates indicated.

Signature	Title	Date
/s/ Harold G. Hamm **Harold G. Hamm**	Chairman of the Board and Chief Executive Officer (principal executive officer)	February 26, 2010
/s/ John D. Hart **John D. Hart**	Senior Vice President, Chief Financial Officer and Treasurer (principal financial and accounting officer)	February 26, 2010
/s/ Robert J. Grant **Robert J. Grant**	Director	February 26, 2010
/s/ David L. Boren **David L. Boren**	Director	February 26, 2010
/s/ Lon McCain **Lon McCain**	Director	February 26, 2010
/s/ Mark E. Monroe **Mark E. Monroe**	Director	February 26, 2010
/s/ H. R. Sanders, Jr. **H. R. Sanders, Jr.**	Director	February 26, 2010