CONTINENTAL RESOURCES INC
Form 10-K
February 25, 2011
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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, 2010

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 Act:

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

Securities registered pursuant to Section 12(g) of the 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 x No ¨

Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K (§229.405 of this chapter) 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 the definitions of large accelerated filer , accelerated filer and smaller reporting company in Rule 12b-2 of the Exchange Act. (Check one):

Large accelerated filer x	Accelerated filer ¨	Non-accelerated filer ¨ (Do not check if a smaller reporting company)	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

The aggregate market value of the voting and non-voting common equity held by non-affiliates of the registrant as of June 30, 2010 was approximately $1.4 billion, based upon the closing price of $44.62 per share as reported by the New York Stock Exchange on such date.

As of February 18, 2011, the registrant had 170,405,395 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 2011, which will be filed with the Securities and Exchange Commission 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:

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

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

Bcf One billion cubic feet of natural gas.

Boe Barrels of crude oil equivalent, with six thousand cubic feet of natural gas being equivalent to one barrel of crude oil based on the average equivalent energy content of the two commodities.

Btu British thermal unit.

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

Conventional play An area that is believed to be capable of producing crude oil and natural gas occurring in discrete accumulations in structural and stratigraphic traps.

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 Exploratory or development well that does not produce crude oil and/or natural gas in economically producible quantities.

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.

Held by production or *HBP* Refers to a mineral lease in which an entity is allowed to operate a property as long as the property produces a minimum paying quantity of crude oil or natural gas.

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.

Injection well A well into which liquids or gases are injected in order to push additional crude oil or natural gas out of underground reservoirs and into the wellbores of producing wells. Typically considered an enhanced recovery process.

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

MBoe One thousand Boe.

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 of natural gas based on the average equivalent energy content of the two commodities.

MMBoe One million Boe.

MMBtu One million British thermal units.

MMcf One million cubic feet of natural gas.

MMcfe One million cubic feet of natural gas equivalent, with one barrel of crude oil being equivalent to six Mcf of natural gas based on the average equivalent energy content of the two commodities.

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 a 50% interest in 100 acres owns 50 net acres.

Play A term applied to a portion of the exploration and production cycle following the identification by geologists and geophysicists of areas with potential crude oil and natural gas reserves.

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.

Prospect A potential geological feature or formation which geologists and geophysicists believe may contain hydrocarbons. A prospect can be in various stages of evaluation, ranging from a prospect that has been fully evaluated and is ready to drill to a prospect that will require substantial additional seismic data processing and interpretation.

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

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.

PV-10 When used with respect to crude oil and natural gas reserves, PV-10 represents 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 the Company s crude oil and natural gas properties. The Company 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.

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.

Royalty interest Refers to the ownership of a percentage of the resources or revenues that are produced from a crude oil or natural gas property. A royalty interest owner does not bear any of the exploration, development, or operating expenses associated with drilling and producing a crude oil or natural gas property.

Spacing The distance between wells producing from the same reservoir. Spacing is often expressed in terms of acres (e.g., 640-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 commodity prices for the period January to December (for year-end 2010 and 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.

Step-out well or *Step outs* A well drilled beyond the proved boundaries of a field to investigate a possible extension of the field.

3D (three dimensional seismic) defined locations Locations that have been subjected to 3D seismic testing. We typically use 3D seismic testing to evaluate reservoir presence and/or continuity. We do not typically evaluate reservoir productivity using 3D seismic technology.

3D seismic Seismic surveys using an instrument to send sound waves into the earth and collect data to help geophysicists define the underground configurations. 3D seismic provides three-dimensional pictures.

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Unconventional play An area that is believed to be capable of producing crude oil and natural gas occurring in accumulations that are regionally extensive, but require recently developed technologies to achieve profitability. These areas tend to have low permeability and may be closely associated with source rock as is the case with gas shale, tight oil and gas sands and coalbed methane.

Undeveloped acreage Lease acreage on which wells have not been drilled or completed to a point that would permit the production of commercial quantities of crude oil and natural gas.

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

Certain statements and information in this report may constitute forward-looking statements within the meaning of the Private Securities Litigation Reform Act of 1995. All statements other than statements of historical fact included in this report are forward-looking statements. When used in this report, the words could, may, believe, anticipate, intend, estimate, expect, project and similar expressions are inte identify forward-looking statements, although not all forward-looking statements contain such identifying words. Forward-looking statements are based on the Company s current expectations and assumptions about future events and currently available information as to the outcome and timing of future events. When considering forward-looking statements, you should keep in mind the risk factors and other cautionary statements described under the heading *Item 1A. Risk Factors* included in this report.

Without limiting the generality of the foregoing, certain statements incorporated by reference, if any, or included in this report constitute forward-looking statements.

Forward-looking statements may include statements about our:

- business strategy;
- future operations;
- reserves;
- technology;
- financial strategy;
- crude oil and natural gas prices;

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

the amount, nature and timing of capital expenditures;

estimated revenues and results of operations;

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;

financial position;

general economic conditions;

credit markets;

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- liquidity and access to capital;
- the impact of regulatory and legal proceedings involving us and of scheduled or potential regulatory changes;
- uncertainty regarding our future operating results; and
- plans, objectives, expectations and intentions contained in this report that are not historical.

We caution you that these forward-looking statements are subject to all of the risks and uncertainties, most of which are difficult to predict and many of which are beyond our control, incident to the exploration for, and the development, production, and sale of, crude oil and natural gas. These risks include, but are not limited to, commodity price volatility, inflation, lack of availability of drilling and production equipment and services, environmental risks, drilling and other operating risks, regulatory changes, the uncertainty inherent in estimating crude oil and natural gas reserves and in projecting future rates of production, cash flows and access to capital, the timing of development expenditures, and the other risks described under *Item 1A. Risk Factors* in this report, registration statements filed from time to time with the SEC, and other announcements we make from time to time.

Readers are cautioned not to place undue reliance on forward-looking statements, which speak only as of the date hereof. Should one or more of the risks or uncertainties described in this report occur, or should underlying assumptions prove incorrect, our actual results and plans could differ materially from those expressed in any forward-looking statements. All forward-looking statements are expressly qualified in their entirety by this cautionary statement. This cautionary statement should also be considered in connection with any subsequent written or oral forward-looking statements that we or persons acting on our behalf may issue.

Except as otherwise required by applicable law, we disclaim any duty to update any forward-looking statements to reflect events or circumstances after the date of this report.

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Part I

You should read this entire report carefully, including the risks described under Item 1A. 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, ours or the Company refer to Continental Resources, Inc. and its subsidiary.

Beginning in 2009, we changed our reporting regions from Rockies, Mid-Continent and Gulf Coast to North, South and East. The North region consists of properties north of Kansas and west of the Mississippi river and includes North Dakota Bakken, Montana Bakken, the Red River units and the Niobrara play in Colorado and Wyoming. The South region includes Kansas and all properties south of Kansas and west of the Mississippi river including the Arkoma Woodford and Anadarko Woodford plays in Oklahoma. The East region contains 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 for, 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 70% of our estimated proved reserves as of December 31, 2010 are located in the North region. We completed an initial public offering of our common stock in 2007, and our common stock trades on the New York Stock Exchange 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 allows us 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 287.0 MMBoe of proved crude oil and natural gas reserves through extensions and discoveries from January 1, 2006 through December 31, 2010 compared to 3.0 MMBoe added through proved reserve acquisitions during that same period.

As of December 31, 2010, our estimated proved reserves were 364.7 MMBoe, with estimated proved developed reserves of 140.4 MMBoe, or 38% of our total estimated proved reserves. Crude oil comprised 62% of our total estimated proved reserves as of December 31, 2010. For the year ended December 31, 2010, we generated crude oil and natural gas revenues of $948.5 million and operating cash flows of $653.2 million. For the year and quarter ended December 31, 2010, daily production averaged 43,318 Boe per day and 48,034 Boe per day, respectively. This represents growth of 16% and 27% as compared to the year and quarter ended December 31, 2009, when daily production averaged 37,324 Boe per day and 37,747 Boe per day, respectively.

The following table summarizes our total estimated proved reserves, PV-10 and net producing wells as of December 31, 2010, average daily production for the three months ended December 31, 2010 and the reserve-to-production index in our principal regions. Our reserve estimates as of December 31, 2010 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 94% of our PV-10, 97% of our proved crude oil reserves, and 94% of our proved natural gas reserves as of December 31, 2010. Our internal technical staff evaluated the remaining properties. Our estimated proved reserves and related future net revenues, PV-10 and Standardized Measure at December 31, 2010 were determined using the 12-month unweighted arithmetic average of the first-day-of-the-month commodity prices for the period of January 2010 through December 2010, without giving effect to derivative transactions, and were held constant throughout the life of the properties. These prices were $79.43 per Bbl for crude oil and $4.38 per MMBtu for natural gas ($71.92 per Bbl for crude oil and $5.07 per Mcf for natural gas net of location and quality differentials).

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	At December 31, 2010						
	Proved reserves (MBoe)	Percent of total	PV-10 (1) (in thousands)	Net producing wells	Average daily production for fourth quarter 2010 (Boe per day)	Percent of total	Annualized reserve/ production index (2)
North Region:							
Bakken field							
North Dakota Bakken	158,042	43.3%	$ 1,982,573	183	17,834	37.1%	24.3
Montana Bakken	40,032	11.0%	632,576	125	4,686	9.8%	23.4
Red River units							
Cedar Hills	38,645	10.6%	981,143	129	10,862	22.6%	9.7
Other Red River units	15,449	4.2%	297,737	106	3,034	6.3%	14.0
Other	3,466	1.0%	54,798	220	1,207	2.5%	7.9
South Region:							
Oklahoma Woodford							
Anadarko Woodford	34,099	9.4%	204,930	13	1,705	3.6%	54.8
Arkoma Woodford	62,347	17.1%	271,749	53	4,403	9.2%	38.8
Other	8,495	2.3%	101,543	293	2,989	6.2%	7.8
East Region	4,137	1.1%	105,165	544	1,314	2.7%	8.6
Total	364,712	100.0%	$ 4,632,214	1,666	48,034	100.0%	20.8

(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, 2010 is $3.8 billion, a $0.8 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 crude oil and natural gas 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 that estimated proved reserves would last assuming current production continued at the same rate. This index is calculated by dividing annualized fourth quarter 2010 production into the estimated proved reserve quantity at December 31, 2010.

The following table provides additional information regarding our key development areas as of December 31, 2010 and the budgeted amounts we plan to spend on exploratory and development drilling, capital workovers, and facilities in 2011:

	Developed acres		Undeveloped acres		2011 Plan	
	Gross	Net	Gross	Net	Gross wells planned for drilling	Capital expenditures (in millions) (1)
North Region:						
Bakken field						
North Dakota Bakken	264,299	119,405	1,021,366	504,244	514	$ 819
Montana Bakken	86,808	66,971	224,704	165,316	16	75
Red River units	149,994	132,247			15	58
Niobrara						
Colorado/Wyoming			103,148	71,712	5	20
Other	69,068	52,698	308,470	171,117		2
South Region:						
Oklahoma Woodford						
Anadarko Woodford	55,320	34,326	350,255	233,216	99	230
Arkoma Woodford	100,430	22,749	47,297	20,864	14	9

Southern Oklahoma			36,440	11,039			
Other	99,597	47,250	80,146	52,193	3		9
East Region	44,720	42,687	172,322	140,734	21		5
Total	870,236	518,333	2,344,148	1,370,435	687	$	1,227

(1) Capital expenditures budgeted for 2011 include amounts for drilling, capital workovers and facilities and exclude budgeted amounts for land of $108 million, seismic of $15 million, and $6 million for vehicles, computers and other equipment. We expect our cash flows from operations and the availability under our revolving credit facility will be sufficient to meet our capital expenditure needs. 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. Further, 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, 2010, crude oil comprises 62% of our total proved reserves and 75% of our 2010 annual production. Although we do pursue liquids-rich natural gas opportunities, such as the Anadarko Woodford shale play in Oklahoma, that have the potential to improve the overall economics of our development projects, we continue to believe that crude oil valuations will be superior to natural gas valuations on a relative Btu basis.

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Growth Through Low-Cost Drilling. Substantially all of our annual capital expenditures are invested in drilling projects and acreage acquisitions. From January 1, 2006 through December 31, 2010, proved crude oil and natural gas reserve additions through extensions and discoveries were 287.0 MMBoe compared to 3.0 MMBoe of proved reserve acquisitions.

Internally Generated 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.

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 technologies. Our production from the Red River units, the Bakken field, and the Oklahoma Woodford shale comprised approximately 13,961 MBoe, or 88%, of our total crude oil and natural gas production during the year ended December 31, 2010.

Acquire Significant Acreage Positions in New or Developing Plays. In addition to the 1,006,391 net undeveloped acres held in the Montana and North Dakota Bakken shale, Colorado and Wyoming Niobrara shale and Oklahoma Woodford shale fields, we held 364,044 net undeveloped acres in other crude oil and natural gas plays as of December 31, 2010. 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 economically producible volumes 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 1,370,435 net undeveloped and 518,333 net developed acres as of December 31, 2010. Approximately 83% of the undeveloped acres are located within unconventional resource plays including, but not limited to, the Bakken shale in North Dakota and Montana, the Woodford shale in Oklahoma and the Niobrara shale in Colorado and Wyoming. The balance of the undeveloped acreage is located 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 1,000 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 7 high pressure air injection (HPAI) floods.

Control Operations Over a Substantial Portion of Our Assets and Investments. As of December 31, 2010, we operated properties comprising 88% 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 7 senior officers have an average of 30 years of crude oil and natural gas industry experience. Additionally, our technical staff, which includes 40 petroleum engineers, 22 geoscientists and 19 landmen, has an average of 16 years experience in the industry.

Strong Financial Position. As of February 18, 2011, we had outstanding borrowings under our revolving credit facility of approximately $95.0 million and available borrowing capacity of $652.6 million. We believe that our planned exploration and development activities will be funded substantially from our operating cash flows and borrowings under our revolving credit facility. Our 2011 capital expenditures budget has been established based on our current expectation of available cash flows from operations and availability under our 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 reduce our capital expenditures to be in line with cash flows from operations.

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Crude Oil and Natural Gas Operations

In December 2008, the SEC adopted new rules related to modernizing reserve calculation and disclosure requirements for crude oil and natural gas companies that became effective prospectively for annual reporting periods ending on or after December 31, 2009. The new rules, which we initially adopted for the year ended December 31, 2009, expanded the definition of crude oil and natural 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 natural 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. The revised rules allow producers to report additional undrilled locations beyond one offset on each side of a producing well when there is reasonable certainty of economic producibility. 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 the 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 in 2009 of new rules related to modernizing the reserve calculation and disclosure requirements resulted in an upward adjustment to our total proved reserves as of December 31, 2009 primarily as a result of the amendments to the definition of crude oil and natural gas reserves and higher crude oil prices. See *Notes to Consolidated Financial Statements Note 15. Supplemental Crude Oil and Natural Gas Information (Unaudited).*

Proved Reserves

Proved reserves are those 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 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 crude oil and/or natural gas actually recovered will equal or exceed the estimate. To achieve reasonable certainty, our internal reserve engineers and Ryder Scott, our independent reserve engineers, 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.

The following tables set forth our estimated proved crude oil and natural gas reserves and the PV-10 as of December 31, 2010 by reserve category. The total Standardized Measure of discounted cash flows as of December 31, 2010 is also presented. Ryder Scott evaluated properties representing approximately 94% of our PV-10, 97% of our proved crude oil reserves, and 94% of our proved natural gas reserves as of December 31, 2010, 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, 2010 were determined using the 12-month unweighted arithmetic average of the first-day-of-the-month commodity prices for the period of January 2010 through December 2010, without giving effect to derivative transactions, and were held constant throughout the life of the properties. These prices were $79.43 per Bbl for crude oil and $4.38 per MMBtu for natural gas ($71.92 per Bbl for crude oil and $5.07 per Mcf for natural gas net of location and quality differentials).

	December 31, 2010			
	Crude Oil (MBbls)	Natural Gas (MMcf)	Total (MBoe)	PV-10 (1) (in thousands)
Proved developed producing	99,565	233,501	138,482	$ 3,097,810
Proved developed non-producing	1,707	1,198	1,907	25,876
Proved undeveloped	123,512	604,869	224,323	1,508,528
Total proved reserves	224,784	839,568	364,712	$ 4,632,214
Standardized Measure				$ 3,785,322

(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, 2010 is $3.8 billion, a $0.8 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 crude oil and natural gas industry use PV-10 as a measure to compare the relative size and value of proved reserves held by companies without regard to the specific tax characteristics of such entities.

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The following table provides additional information regarding our proved crude oil and natural gas reserves by region as of December 31, 2010.

	Proved Developed			Proved Undeveloped		
	Crude Oil (MBbls)	Natural Gas (MMcf)	Total (MBoe)	Crude Oil (MBbls)	Natural Gas (MMcf)	Total (MBoe)
North Region:						
Bakken field						
North Dakota Bakken	33,233	46,801	41,033	96,227	124,693	117,009
Montana Bakken	15,405	16,651	18,180	18,337	21,088	21,852
Red River units						
Cedar Hills	31,752	20,398	35,152	3,493		3,493
Other Red River units	12,840	437	12,913	2,536		2,536
Other	2,226	6,418	3,296	20	900	170
South Region:						
Oklahoma Woodford						
Anadarko Woodford	548	24,302	4,598	2,438	162,379	29,501
Arkoma Woodford	102	75,304	12,653	393	295,809	49,694
Other	1,377	42,709	8,495			
East Region	3,789	1,679	4,069	68		68
Total	101,272	234,699	140,389	123,512	604,869	224,323

We have historically added reserves through our exploration program and development activities. See *Item 1. Business Crude Oil and Natural Gas Operations*. Reserves at December 31, 2010 and 2009 were computed using the 12-month unweighted average of the first-day-of-the-month commodity prices as required by the new SEC rules. Reserves at December 31, 2008 were computed using year-end commodity prices pursuant to previous SEC rules. Changes in proved reserves were as follows for the periods indicated:

	Year Ended December 31,		
MBoe	**2010**	**2009**	**2008**
Proved reserves at beginning of year	257,293	159,262	134,615
Revisions of previous estimates	27,629	1,195	(13,224)
Extensions, discoveries and other additions	95,233	110,454	47,647
Production	(15,811)	(13,623)	(12,006)
Sales of minerals in place			
Purchases of minerals in place	368	5	2,230
Proved reserves at end of year	364,712	257,293	159,262

Revisions. Revisions represent changes in previous reserves estimates, 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. Revisions for the year ending December 31, 2008 were primarily due to lower commodity prices at the end of 2008 compared to 2007. Revisions for the year ended December 31, 2010 were due to better than anticipated production performance and higher average commodity prices throughout 2010 as compared to 2009.

Extensions, discoveries and other additions. These are additions to our 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 for the year ended December 31, 2009 include increases in proved undeveloped locations as a result of the change in the SEC s rules in 2009 to allow producers to report additional undrilled locations beyond one offset on each side of a producing well where there is reasonable certainty of economic producibility. Extensions, discoveries and other additions for the year ended December 31, 2010 were primarily due to increases in proved reserves associated with our successful drilling activity in the Bakken field in North Dakota.

We expect that a significant portion of future reserve additions will come from our major development projects including the Bakken and Oklahoma Woodford plays. We may also purchase proved properties in strategic acquisitions.

Qualifications of Technical Persons and Internal Controls Over Reserves Estimation Process. Ryder Scott, our independent reserve engineers, estimated, in accordance with generally accepted petroleum engineering and evaluation principles and definitions and guidelines established by the SEC, 94% of our PV-10, 97% of our proved crude oil reserves, and 94% of our proved natural gas reserves as of December 31, 2010 included in this Annual Report on Form 10-K. The Ryder Scott technical persons responsible for preparing the reserve 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.

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We maintain an internal staff of petroleum engineers and geoscience professionals who work closely with our independent reserve engineers 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 by 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 Vice President Resource Development is the technical person primarily responsible for overseeing the preparation of our reserve estimates. He has a Bachelor of Science degree in Petroleum Engineering, an MBA in Finance and 25 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 Vice President Resource Development reports directly to our President and Chief Operating Officer. The reserve estimates are reviewed and approved by the Chief Operating Officer and certain members of senior management.

Proved Undeveloped Reserves. Our proved undeveloped (PUD) reserves at December 31, 2010 were 224,323 MBoe, consisting of 123,512 MBbls of crude oil and 604,869 MMcf of natural gas. In 2010, we developed approximately 11% of our proved undeveloped reserves booked as of December 31, 2009 through the drilling of 130 gross (60.4 net) development wells at an aggregate capital cost of approximately $310 million. Also in 2010, we removed the reserves associated with 61 gross (23.9 net) PUD locations because, in the opinion of management, such locations were no longer expected to be developed within the 5 year timeline required by SEC rules. This resulted in the removal of 40.1 Bcf of proved undeveloped natural gas reserves (6.7 MMBoe) in 2010. Estimated future development costs relating to the development of proved undeveloped reserves are projected to be approximately $865 million in 2011, $1,055 million in 2012, and $811 million in 2013.

Since our entry into the Bakken field we have acquired a substantial leasehold position. Our drilling programs to date have focused on proving our undeveloped leasehold acreage through strategic exploratory drilling, thereby increasing the amount of leasehold acreage in the secondary term of the lease with no further drilling obligations, i.e. categorized as held by production (HBP) and resulting in a reduced amount of leasehold acreage in the primary term of the lease with drilling obligations. While we will continue to drill strategic exploratory wells and build on our current leasehold position, we will simultaneously focus on drilling programs over the next 5 years which harvest our PUD locations. Our current 5 year plan anticipates that full development of our PUD inventory will comprise over one-third of our projected level of drilling activity and generate additional PUD locations as our current inventory is harvested.

Developed and Undeveloped Acreage

The following table presents our total gross and net developed and undeveloped acreage by region as of December 31, 2010:

	Developed acres		Undeveloped acres		Total	
	Gross	Net	Gross	Net	Gross	Net
North Region:						
Bakken field						
North Dakota Bakken	264,299	119,405	1,021,366	504,244	1,285,665	623,649
Montana Bakken	86,808	66,971	224,704	165,316	311,512	232,287
Red River units	149,994	132,247			149,994	132,247
Niobrara						
Colorado/Wyoming			103,148	71,712	103,148	71,712
Other	69,068	52,698	308,470	171,117	377,538	223,815
South Region:						
Oklahoma Woodford						
Anadarko Woodford	55,320	34,326	350,255	233,216	405,575	267,542
Arkoma Woodford	100,430	22,749	47,297	20,864	147,727	43,613
Southern Oklahoma			36,440	11,039	36,440	11,039
Other	99,597	47,250	80,146	52,193	179,743	99,443
East Region	44,720	42,687	172,322	140,734	217,042	183,421
Total	870,236	518,333	2,344,148	1,370,435	3,214,384	1,888,768

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The following table sets forth the number of gross and net undeveloped acres as of December 31, 2010 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:

	2011		2012		2013	
	Gross	Net	Gross	Net	Gross	Net
North Region:						
Bakken field						
North Dakota Bakken	229,040	85,969	216,013	105,602	328,682	160,385
Montana Bakken	16,003	14,925	23,210	17,563	82,058	54,158
Red River units						
Niobrara						
Colorado/Wyoming	696	696	1,079	1,079	43,381	31,102
Other	72,584	44,088	38,699	21,359	48,448	38,702
South Region:						
Oklahoma Woodford						
Anadarko Woodford	135,836	88,520	60,851	37,223	137,014	95,088
Arkoma Woodford	17,174	7,123	12,323	7,141	7,557	5,500
Southern Oklahoma	18,685	3,206	6,140	3,015	10,788	4,434
Other	57,589	44,766	3,609	1,842	5,953	3,859
East Region	41,042	32,286	60,769	54,453	38,678	30,618
Total	588,649	321,579	422,693	249,277	702,559	423,846

Drilling Activity

During the three years ended December 31, 2010, we drilled exploratory and development wells as set forth in the table below:

	2010		2009		2008	
	Gross	Net	Gross	Net	Gross	Net
Exploratory wells:						
Crude oil	42	11.8	14	6.5	41	18.2
Natural gas	25	10.9	34	9.0	73	19.5
Dry holes	4	2.2	16	9.0	12	8.9
Total exploratory wells	71	24.9	64	24.5	126	46.6
Development wells:						
Crude oil	231	91.5	106	39.1	153	89.3
Natural gas	44	5.2	45	4.1	72	13.4
Dry holes	3	1.0	2	0.1	8	3.2
Total development wells	278	97.7	153	43.3	233	105.9
Total wells	349	122.6	217	67.8	359	152.5

As of December 31, 2010, there were 151 gross (47.9 net) wells in the process of drilling, completing or waiting on completion.

As of February 18, 2011, we operated 38 rigs on our properties. Our rig activity during 2011 will depend 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 for 2011. We believe our cash flows from operations and borrowing availability under our revolving credit facility will be sufficient to satisfy our 2011 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. Further, 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.

As referred to throughout this report, a play is a term applied to a portion of the exploration and production cycle following the identification by geologists and geophysicists of areas with potential crude oil and natural gas reserves. Conventional plays are areas that

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are believed to be capable of producing crude oil and natural gas occurring in discrete accumulations in structural and stratigraphic traps. Unconventional plays are areas that are believed to be capable of producing crude oil and natural gas occurring in accumulations that are regionally extensive, but require recently developed technologies to achieve profitability. Unconventional plays tend to have low permeability and may be closely associated with source rock as is the case with gas shale, tight oil and gas sands and coalbed methane. Our operations in unconventional plays include operations in the Bakken and Woodford shales and the Red River units. Our operations within conventional plays include operations in the Trenton-Black River of Michigan, Lodgepole of North Dakota, Morrow-Springer of western Oklahoma and Frio in south Texas. In general, unconventional plays require the application of more advanced technology and higher drilling and completion costs to produce relative to conventional plays. These technologies can include large hydraulic fracture treatments, horizontal wellbores, multilateral wellbores, or some other technique or combination of techniques to expose more of the reservoir to the wellbore.

References throughout this report to 3D seismic refer to seismic surveys of areas by means of an instrument which records the travel time of vibrations sent through the earth and the interpretation thereof. By recording the time interval between the source of the shock wave and the reflected or refracted shock waves from various formations, geophysicists are better able to define the underground configurations. 3D defined locations are those locations that have been subjected to 3D seismic testing. We typically use 3D seismic testing to evaluate reservoir presence and/or continuity. We do not typically evaluate reservoir productivity using 3D seismic technology.

North Region

Our properties in the North region represented 85% of our PV-10 as of December 31, 2010. During the three months ended December 31, 2010, our average daily production from such properties was 33,214 net Bbls of crude oil and 26,456 net Mcf of natural gas. Our principal producing properties in this region are in the Bakken field and the Red River units.

Bakken Field

The Bakken field of North Dakota and Montana has become one of the premier crude oil resource plays in the United States. It has been described by the United States Geological Survey (USGS) as the largest continuous crude oil accumulation it has ever assessed. Estimates of recoverable reserves for the Bakken field have grown from 4.3 billion barrels of crude oil, as published in a report issued by the USGS in April 2008, to potentially 11 billion barrels of crude oil in North Dakota alone, as reported by the North Dakota Industrial Commission (NDIC) in January 2011. The increase in reserves is a result of improved drilling and completion technologies and the additional reserves found in the Three Forks formation, which is now recognized as part of the Bakken petroleum system. Drilling activity and production rates in the Bakken field continued to increase in 2010, reaching record levels in North Dakota, according to a report issued by the NDIC in January 2011. As of February 18, 2011, there were 174 rigs drilling in the Bakken field, up 96% from the 89 rigs that were drilling as of January 25, 2010. We continue to be a leader in the development and expansion of the Bakken field. We control one of the largest leasehold positions with approximately 1,597,177 gross (855,936 net) acres as of December 31, 2010. We are also the most active driller in the Bakken field, with 23 operated rigs drilling as of February 18, 2011. During 2010 we completed 233 gross (76.5 net) wells in the Bakken field. Our properties within the Bakken field represented 56% of our PV-10 as of December 31, 2010 and 47% of our average daily Boe production for the three months ended December 31, 2010. As of December 31, 2010 we had completed 648 gross (260.5 net) wells in the Bakken field. Our inventory of proven undeveloped drilling locations in the Bakken field as of December 31, 2010 totaled 842 gross (393.7 net) wells.

2010 proved to be an exceptional year for us in the Bakken field as we saw our production, reserves and acreage position grow to record levels while substantial portions of our undeveloped acreage were de-risked due to the record breaking drilling activity in North Dakota. Our Bakken field production averaged 25,589 net Boe per day during the month of December 2010, up 78% from our average daily Bakken field production in December 2009. Total proved Bakken field reserves at December 31, 2010 were 198 MMBoe, up 47% over our proved Bakken field reserves as of December 31, 2009. Our net acreage position in the Bakken field increased 33% during 2010, from 645,347 net acres as of December 31 2009 to 855,936 net acres as of December 31, 2010. Approximately 22% of our net acreage is developed and 78% of our net acreage is undeveloped as of December 31, 2010.

We plan to invest approximately $845 million drilling 530 gross (131.7 net) wells in the Bakken field during 2011. Approximately 91% will be invested in North Dakota and the remaining 9% will be invested in Montana. We plan to keep 23 rigs drilling in the Bakken field throughout the year, with 21 rigs located in North Dakota and 2 rigs in Montana.

North Dakota Bakken. Our production and reserve growth in the Bakken field during 2010 came primarily from our activities in North Dakota. Production increased to an average rate of 20,860 net Boe per day during the month of December 2010, up 129% from the average daily rate in December 2009. Proved reserves grew 50% year over year to 158 MMBoe as of December 31, 2010. Our estimated ultimate recoverable reserves per well (1,280-acre spacing) also increased during the year from 430 MBoe gross to 518 MBoe gross based on historical well performance. As of December 31, 2010, our North Dakota Bakken properties represented 43% of our PV-10 and 37% of our average daily Boe production for the three months ended December 31, 2010. We completed 222 gross (71 net) wells during 2010, bringing our total number of wells

drilled in the North Dakota Bakken to 475 gross (150.2 net) as of December 31, 2010. As of December 31, 2010, we had 1,285,665 gross (623,649 net) acres in the North Dakota Bakken field, of which 19% of the net acreage is developed and 81% of the net acreage is undeveloped. Our inventory of proven net undeveloped locations stood at 747 gross (329.5 net) wells as of December 31, 2010.

One of the more significant outcomes of the 2010 drilling activity in the North Dakota Bakken was the expansion of the play west of the Nesson Anticline. Technological breakthroughs demonstrated that widespread commercial production can be achieved in this area by increasing fracture stimulation treatments where necessary. Based on this information, we expanded our leasing effort and acquired an additional 141,800 net acres in the North Dakota Bakken during 2010, increasing our net acreage position by 29% over our North Dakota Bakken net acreage position as of December 31, 2009.

Another significant achievement during 2010 was the successful implementation of our ECO-Pad™ technology. ECO-Pad technology allows 4 wells (2 Bakken and 2 Three Forks) to be drilled from a single drilling pad, which reduces drilling costs, completion costs and environmental impact by centralizing operations on a single pad. Drilling costs are saved by utilizing a walking rig, which moves between wells on hydraulic feet that eliminate the need to breakdown the rig each time it moves from one well to another well. Completion costs are saved by conducting fracture stimulation treatments on multiple wells in one continuous operation. Centralizing operations and production facilities reduces the size of the pad needed by as much as 75%. Our first ECO-Pad operation, the Arthur-Hegler, was completed in August 2010, flowing at a combined maximum 24-hour rate of 4,350 Boe per day. As of December 31, 2010, we had completed 4 ECO-Pad locations and had 4 ECO-Pad rigs drilling. We believe our ECO-Pad technology is a key to maximizing the development of the Bakken field, and we plan to increase the use of this technology as the field matures.

During 2010 we increased the number of fracture stimulation stages per well from approximately 18 stages to as many as 30 stages. Although there are always overriding geologic factors that influence production, the increase in recoverable reserves we announced in 2010 can be attributed primarily to the increased number of fracture stimulation stages used per well. We are studying these results to optimize future fracture stimulations in the field.

During 2011, we plan to invest approximately $771 million drilling 514 gross (120.6 net) wells in the North Dakota Bakken field. The drilling will include development wells along our Nesson Anticline acreage and step-out wells west of the Nesson Anticline to continue expanding the proven extents of the Bakken and Three Forks reservoirs underlying our acreage. The majority of our drilling will be on 1,280-acre spacing but will include some 640-acre infield locations and dual zone development. In time, we expect that the North Dakota Bakken field will be developed on 320-acre spacing like the Elm Coulee field in Montana. As of February 18, 2011, we had 21 operated rigs drilling in the North Dakota Bakken and plan to maintain 21 operated rigs drilling in the play throughout 2011.

Montana Bakken. Our Montana Bakken production is located primarily in the Elm Coulee field in Richland County, Montana. The Elm Coulee field is listed by the Energy Information Administration as the 17th largest onshore field in the lower 48 states of the United States ranked by proved liquid reserves in 2009. Since drilling our first well in August 2003, we have completed a total of 171 gross (108.6 net) wells in the field as of December 31, 2010. Year over year, production in 2010 was down 18%, reflecting our limited drilling activity in the field during 2010. The majority of our drilling was conducted during the second half of 2010, and production during the month of December 2010 was down only 10% from the average daily production in December 2009. As of December 31, 2010 our Montana Bakken properties represented 14% of our PV-10 and 10% of our average daily Boe production for the three months ended December 31, 2010. During the year we added 98,344 gross (68,788 net) acres in the Montana Bakken play. As of December 31, 2010, we owned 311,512 gross (232,287 net) acres, of which 29% of the net acreage is developed and the remaining 71% of the net acreage is undeveloped.

During the year ended December 31, 2010, using the latest drilling and completion technologies, we completed 11 gross (5.5 net) wells to further develop the field and test the potential to expand the limits of the Elm Coulee field. The Rognas 2-22H well, which is strategically located along the northern edge of the Elm Coulee field, was completed flowing at a 24-hour maximum rate of 1,014 Boe per day. The Rognas 2-22H was completed using current drilling and cased hole, multi-stage fracture stimulation technology and has significantly outperformed offsetting wells that were completed using older open hole completion technology. These results are encouraging and indicate that we may be able to extend the limits of the Elm Coulee field using these technologies. We will continue testing this concept in 2011.

We plan to invest approximately $74 million drilling 16 gross (11.1 net) wells in the Montana Bakken during 2011. Our drilling will focus in the Elm Coulee field area but will also include some strategic step-out wells to further test our undeveloped acreage immediately north of the Elm Coulee field. As of February 18, 2011 we had 2 rigs drilling in the Montana Bakken and we plan to maintain 2 rigs in the play throughout 2011. As of December 31, 2010, we had 95 gross (64.2 net) proven undeveloped locations identified in the Montana Bakken.

Red River Units

Our Red River units represent 28% of our PV-10 as of December 31, 2010 and 34% of our average daily North region Boe production for December 2010. 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, which was listed by the Energy Information Administration in 2008 as the 7th largest onshore field in the lower 48 states of 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 2011. We have allocated $58 million of our capital expenditure budget to the Red River units, which will support 2 operated rigs and a significant investment in facilities and infrastructure.

Cedar Hills Units. Cedar Hills North unit (CHNU) is located in Bowman and Slope Counties, North Dakota. We drilled the initial horizontal well in CHNU, the Ponderosa 1-15, in April 1995. As of December 31, 2010, we had drilled 235 horizontal wells within this 49,700-acre unit, with 116 producing wellbores and the remainder serving as injection wellbores. We own a 98% working interest and operate the CHNU.

Cedar Hills West unit (CHWU), in Fallon County, Montana, is contiguous to the northern portion of CHNU. As of December 31, 2010, this 7,800-acre unit contained 11 horizontal producing wells and 5 horizontal injection wells. We own and operate 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 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. During February 2008, the transition started to have full scale water injection and this transition was completed in June of 2010 when we stopped our air injection at Cedar Hills after injecting nearly 80 Bcf of air into the reservoir. We have seen continued success from our increased density drilling program which supported the idea that we could more economically inject water than air in these units. In response to our enhanced recovery and increased drilling efforts, our net daily production increased from 2,185 Boe per day in November 2003 to 10,789 Boe per day in December 2010. During 2011, we plan to drill 12 new horizontal wells in the Cedar Hills units continuing with our increased density for both the producing wells and injection wells, and improving and upgrading production and injection facilities. In 2011, we plan to invest approximately $35 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 51 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 and we operate and own an average 77% working interest in the three units. Production from the units averaged 1,241 net Bbls of crude oil and 1,721 net Mcf of natural gas per day during December 2010. In May 2010 we began the installation of two 15 MMcf per day electric air compressors to supplement and ultimately replace our more costly natural gas-fired compressors which currently inject 24 MMcf of air per day. During the second quarter of 2011, we plan to finalize the installation. In 2011, we plan to invest approximately $7 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 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 2010, 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 2010 was 1,421 net Bbls of crude oil per day. In 2011, we plan to invest approximately $4 million for capital workovers and facilities which will include installing two 14 MMcf per day electric air compressors to supplement and ultimately replace the less efficient and higher maintenance compressors which currently inject 10 MMcf of air per day. This installation started in May 2010 and will be completed during the first quarter of 2011.

Niobrara

The Upper Cretaceous Niobrara formation has emerged as another potential crude oil resource play in various basins throughout the northern Rocky Mountain region. As with most resource plays, the Niobrara has a history of producing through conventional technology with some of the earliest production dating back to the early 1900s. Individual fields have produced up to 12 MMBoe and individual wells have produced up to 2.1 MMBoe. Natural fracturing has played a key role in producing the Niobrara historically due to the low porosity and low permeability of the formation. Because of this, conventional production has been very localized and limited in area extent. We believe the Niobrara can be produced on a more widespread basis using today s horizontal multi-stage fracture stimulation technology where the Niobrara is thermally mature. Based on studies conducted by our geotechnical teams, we have acquired 103,148 gross (71,712 net) acres in prospective portions of the DJ Basin of Colorado and Wyoming.

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DJ Basin. The DJ Basin Niobrara play emerged as a crude oil resource play in 2010 and attracted a flurry of leasing activity based on drilling results announced early in 2010. Drilling activity increased during the year, and at December 31, 2010 there were 12 rigs drilling horizontal Niobrara wells in the DJ Basin, with 279 outstanding permits to drill additional horizontal Niobrara wells in the basin. Although drilling activity ramped up during the year, the play is in its early stages, and completion results and production histories are limited. A total of 15 Niobrara completions have been published as of December 31, 2010. Initial production rates for these Niobrara producers ranged from 87 Bbls of crude oil per day to 1,558 Bbls of crude oil per day.

As of December 31, 2010, we owned 103,148 gross (71,712 net) acres in the DJ Basin. Approximately 33% of the net acreage is located in Weld and Morgan Counties, Colorado and 67% in Laramie, Goshen and Platte counties in Wyoming. Here, the Niobrara is found at an average depth of approximately 6,000 feet, and the targeted B-bench chalk ranges from 50 to 100 feet thick. We spud our first horizontal well in Weld County, Colorado, the Newton 1-4H, in early February 2011. The Newton 1-4H is the first 1,280-acre spaced well drilled in the Niobrara play, with a targeted lateral length of 9,200 feet. To date, all wells in the play have been drilled on 640-acre spacing with laterals of 4,500 feet or less. By increasing the lateral length, we expect to get more reserves per well at a lower cost.

In 2011, we plan to invest approximately $20 million drilling 5 gross (3.3 net) wells in the DJ Basin Niobrara play. We also plan to acquire 80 square miles of 3D seismic data during the first quarter of 2011 to guide future drilling in the play.

Big Horn Basin and Other

Our wells within the Big Horn Basin in northern Wyoming and other areas within the North region represented 1% of our PV-10 as of December 31, 2010 and 3% of our average daily Boe production for the three months ended December 31, 2010. 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 locations at the Red River and Lodgepole structures in North Dakota and Montana, and horizontal Fryburg opportunities in North Dakota.

South Region

Our properties in the South region represented 12% of our PV-10 as of December 31, 2010 and 19% of our average daily Boe production for the three months ended December 31, 2010. During the three months ended December 31, 2010, our average daily production from such properties was 790 net Bbls of crude oil and 49,843 net Mcf of natural gas, up 27% from same period 2009. Our principal producing properties in this region are located in the Anadarko and Arkoma basins of Oklahoma, as well as various basins of Texas and Louisiana.

Oklahoma Woodford Shale

The Oklahoma Woodford is a widespread unconventional shale reservoir that produces crude oil, natural gas and natural gas condensate in various basins across the state of Oklahoma. Our principal producing properties in the Oklahoma Woodford are located in the Arkoma and Anadarko basins. Combined, these properties represented 10% of our PV-10 as of December 31, 2010 and 13% of our net average daily Boe production for the three months ended December 31, 2010. Production from the Oklahoma Woodford for 2010 totaled 1,928 MBoe (11,568 MMcfe), up 17% over 2009. Production increased throughout the year, and the average daily production for our Oklahoma Woodford properties for the month of December 2010 was 6,144 Boe per day, up 41% over our daily average production for the month of December 2009. As of December 31, 2010, we held 589,742 gross (322,194 net) acres in the play. As of December 2010, 18% of the net acreage is developed and the remaining 82% of the net acreage is undeveloped.

During 2010 we completed 67 gross (15.1 net) Oklahoma Woodford wells. During 2011, we plan to invest approximately $230 million drilling 113 gross (31.1 net) wells in the Oklahoma Woodford. As of February 18, 2011 we had 11 rigs drilling in the Oklahoma Woodford and expect to maintain 8 to 10 rigs in the play throughout 2011.

Arkoma Woodford Shale. The Arkoma Woodford represented 6% of our PV-10 as of December 31, 2010 and 9% of our average daily Boe production for the three months ended December 31, 2010. Year-over-year, Arkoma Woodford production was down 5% due to our

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scaled back drilling program in 2010. During the month of December 2010, however, our Arkoma Woodford production averaged 4,253 net Boe per day, up 19% over our average daily production in December 2009, reflecting results of wells we completed in the second half of 2010. As of December 31, 2010 we have completed a total of 387 gross (57.5 net) wells in the Arkoma Woodford play.

During 2010, we completed a total of 50 gross (6.5 net) wells, as compared to 71 gross (8.5 net) wells in 2009. These completions included a combination of 640-acre exploratory and 80-acre infield development type wells. We also licensed 10 squares miles of 3D seismic data during 2010 to provide guidance for our exploration and development drilling in the East McAlester area. In total, we now own approximately 150 square miles of proprietary and non-proprietary 3D seismic data in the Arkoma basin to complement our drilling effort. As of December 31, 2010, we owned approximately 147,727 gross (43,613 net) acres in the Arkoma Woodford play, of which 52% of our net acreage is developed and the remaining 48% of our net acreage is undeveloped. A total of 339 gross (94.1 net) proven undeveloped locations have been identified on this acreage as of December 31, 2010.

In 2011, we plan to invest approximately $9 million to drill 14 gross (2.3 net) wells in the Arkoma Woodford play. As of February 18, 2011, we had 1 operated rig drilling in the Arkoma Woodford play.

Anadarko Woodford Shale. The Anadarko Woodford represented 4% of our PV-10 as of December 31, 2010 and 4% of our average daily Boe production for the three months ended December 31, 2010. Our Anadarko Woodford production grew 333% year-over-year due to our increased drilling activity in 2010. During the month of December 2010, our Anadarko Woodford production averaged 1,891 net Boe per day, up 136% over our average daily production in December 2009.

We control one of the largest acreage positions in the Anadarko Woodford play, with 405,575 gross (267,542 net) acres under lease as of December 31, 2010. This acreage is located in Canadian, Blaine, Dewey, Caddo, Grady and McClain counties in Oklahoma, extending 51 miles northwest and 75 miles southeast from the Cana field area, where the initial discovery was made in late 2007. Approximately 68% of our acreage is located in our NW Cana project and 32% is located in our SE Cana project.

Competition for acreage and equipment in the Anadarko Woodford grew rapidly during 2010 in response to continued success in the Cana field and our drilling success in our NW Cana and SE Cana projects. The industry rig count tripled during the year, from 15 rigs in January 2010 to 48 rigs as of February 18, 2011. Results from the 2010 drilling activity demonstrated that production from the Woodford Shale is widespread and repeatable, and suggests that the Anadarko Woodford may prove to contain greater recoverable reserves than the Arkoma Woodford.

During 2010, we completed a total of 16 gross (8.2 net) wells as compared to 4 gross (2.6 net) wells in 2009. Our 2010 drilling program was strategically designed to delineate the extent of the productive Anadarko Woodford on our acreage. Under this successful program, we completed key wells in both our NW Cana and SE Cana projects, demonstrating that the productive Anadarko Woodford fairway extends at least 90 miles from known production at our Brown 1-2H well in Dewey County (NW Cana) to our Dana 1-29H well in Grady County (SE Cana). In NW Cana, the Doris 1-25H well (98% WI) was completed flowing at an initial 24-hour test rate of 4.5 MMcf of natural gas per day and 72 Bbls of crude oil per day. The Doris 1-25H well was located 4 miles south of our initial discovery well, the Brown 1-2H (100% WI) that was completed in September 2009. The Brown 1-2H well was completed flowing at 4.2 MMcf of natural gas per day and 102 Bbls of crude oil per day and produced a total of 1,208 MMcf of natural gas and 15,895 Bbls of crude oil as of December 31, 2010. In our SE Cana project we completed the Dana 1-29H well (79% WI) flowing at 2.5 MMcf per day of liquids-rich natural gas and 88 Bbls of crude oil per day during its initial 24-hour test period. The Dana 1-29H well was a key completion for us in SE Cana, as it confirmed our geologic model that higher production rates can be achieved from the upper siliceous member of the Woodford shale in SE Cana. In January 2011, we confirmed the success of the Dana 1-29H well by completing the Sprowls 1-14H well located 17 miles north of the Dana 1-29H well. The Sprowls 1-14H well (100% WI) was completed flowing at 2.8 MMcf of natural gas per day and 96 Bbls of crude oil per day during its initial 24-hour test period. Based on these positive results, we increased our operated rig count in the Anadarko Woodford from 1 operated rig in January 2010 to 10 operated rigs as of February 18, 2011.

An upside to the Anadarko Woodford is the potential to encounter additional pay from reservoirs overlying the Woodford. With the Anadarko basin being one of the more prolific crude oil and natural gas producing basins in the United States, there are up to 12 conventional reservoirs overlying the Anadarko Woodford shale. All of these conventional reservoirs have the potential to produce locally under our Anadarko Woodford acreage. A good example is our Rother 1-4H well (100% WI), which encountered a productive reservoir in an overlying Springer sand while drilling to the Woodford shale. After completing the Rother 1-4H well as a Woodford producer, we drilled a second well, the Rother 2-4 (80% WI) to produce the Springer reservoir. The Rother 2-4 well produced 4.9 MMcf of natural gas per day and 91 Bbls of crude oil per day during its initial 24-hour test period. Springer sand reservoirs can be quite prolific, and since being completed in November 2010, the Rother 2-4 well has produced 221 MMcf of natural gas and 3,926 Bbls of crude oil as of December 31, 2010. To date, 37% of our Woodford wells have encountered productive reservoirs in overlying Tonkawa, Red Fork, Morrow, Springer and/or Mississippian reservoirs, while drilling to the Woodford shale.

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In 2011, we plan to invest approximately $221 million to drill 99 gross (28.8 net) wells to further delineate and develop the Anadarko Woodford shale on our acreage. As of February 18, 2011, we had 10 operated rigs drilling in the Anadarko Woodford play, and expect to have 2 additional rigs drilling in the play by the end of first quarter 2011. To support our drilling program, we are investing approximately $12 million dollars to acquire approximately 500 square miles of proprietary 3D seismic to guide future drilling on our acreage. As of December 31, 2010, we had a total of 80 gross (41.4 net) proven undeveloped locations identified on our Anadarko Woodford acreage.

Conventional Anadarko Basin and Gulf Coast

Our conventional producing properties in the Anadarko basin and Gulf Coast areas represented 2% of our PV-10 as of December 31, 2010 and 6% of our average daily Boe production for the three months ended December 31, 2010. The properties primarily include our legacy assets in Oklahoma along the Anadarko Basin Shelf, the Jefferson Island Salt Dome in Iberia Parish, Louisiana, and producing properties in Nueces County, Texas. We continue to maximize the performance of these properties through workovers, recompletions and drilling as warranted. Year-over-year our conventional Anadarko and Gulf Coast production declined 13% due to normal production declines and our limited drilling activity. During the month of December 2010 however, production averaged 3,269 net Boe per day, up 12% over our average daily production in December 2009 reflecting results of wells we completed in the second half of 2010. We completed 11 gross (4.9 net) wells in the conventional Anadarko and Gulf Coast areas during 2010.

East Region

Our properties in the East region represent 2% of our PV-10 as of December 31, 2010. During the three months ended December 31, 2010, our average daily production from such properties was 1,292 net Bbls of crude oil and 128 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 33% of our PV-10 in the East region as of December 31, 2010 and 59% of our average daily East region Boe production for the three months ended December 31, 2010. 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 15% of our PV-10 in the East region as of December 31, 2010 and 16% of our average daily East region Boe production for the three months ended December 31, 2010. We owned approximately 76,500 gross (58,800 net) acres in the play as of December 31, 2010. Since drilling our first well on the properties in 2007, we have drilled and completed 20 gross (12.3 net) wells with net success of 55%.

Drilling on these properties has been guided by our proprietary 3D seismic interpretation techniques. We currently own 46 square miles of 3D seismic data on the properties and have numerous additional drilling locations. We plan to acquire an additional 10.6 square miles of 3D seismic during 2011 to identify additional drilling opportunities.

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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, 2010, 2009 and 2008 in total and for each field containing 15 percent or more of our total proved reserves as of December 31, 2010:

	Year Ended December 31,		
	2010	**2009**	**2008**
Net production volumes:			
Crude oil (MBbls) [(1)]			
North Dakota Bakken	4,450	2,257	1,145
Arkoma Woodford	9	13	8
Total Company	11,820	10,022	9,147
Natural gas (MMcf)			
North Dakota Bakken	3,994	1,729	720
Arkoma Woodford	8,726	9,152	5,407
Total Company	23,943	21,606	17,151
Crude oil equivalents (MBoe)			
Total Company	15,811	13,623	12,006
Average sales prices: [(2)]			
Crude oil ($/Bbl)			
North Dakota Bakken	$ 70.09	$ 55.06	$ 83.68
Arkoma Woodford	72.88	58.46	80.74
Total Company	70.69	54.44	88.87
Natural gas ($/Mcf)			
North Dakota Bakken	6.38	4.73	10.62
Arkoma Woodford	4.22	3.50	7.24
Total Company	4.49	3.22	6.90
Crude oil equivalents ($/Boe)			
Total Company	59.70	45.10	77.66
Costs and expenses: [(2)]			
Production expenses ($/Boe)			
North Dakota Bakken	$ 2.94	$ 3.64	$ 14.06
Arkoma Woodford	2.39	2.10	7.87
Total Company	5.87	6.89	8.40
Production taxes and other expenses ($/Boe)	4.82	3.37	4.84
General and administrative expenses ($/Boe) [(3)]	3.09	3.03	2.95
DD&A expense ($/Boe)	15.33	15.34	12.30

(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 78 MBbls more than production volumes for the year ended December 31, 2010, 82 MBbls less than production volumes for the year ended December 31, 2009 and 97 MBbls more than production volumes for the year ended December 31, 2008.

(2) Average sales prices and per unit costs have been calculated using sales volumes and exclude any effect of derivative transactions.

(3) General and administrative expense ($/Boe) includes non-cash equity compensation expense of $0.74 per Boe, $0.84 per Boe, and $0.75 per Boe for the years ended December 31, 2010, 2009 and 2008, respectively.

The following table sets forth information regarding our average daily production by region during the fourth quarter of 2010:

	Fourth Quarter 2010 Daily Production		
	Crude Oil (Bbls per day)	**Natural Gas (Mcf per day)**	**Total (Boe per day)**

North Region:			
Bakken field			
North Dakota Bakken	15,393	14,648	17,834
Montana Bakken	4,076	3,662	4,686
Red River units			
Cedar Hills	10,372	2,938	10,862
Other Red River units	2,684	2,097	3,034
Other	689	3,111	1,207
South Region:			
Oklahoma Woodford			
Anadarko Woodford	183	9,135	1,705
Arkoma Woodford	19	26,303	4,403
Other	588	14,404	2,989
East Region	1,292	129	1,314
Total	35,296	76,427	48,034

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Productive Wells

Gross wells represent the number of wells in which we own a working interest and net wells represent the total of our fractional working interests owned in gross 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, 2010:

	Crude Oil Wells		Natural Gas Wells		Total Wells	
	Gross	Net	Gross	Net	Gross	Net
North Region:						
Bakken field						
North Dakota Bakken	510	182	5	1	515	183
Montana Bakken	191	124	2	1	193	125
Red River units	257	233	2	2	259	235
Other	235	218	5	2	240	220
South Region:						
Oklahoma Woodford						
Anadarko Woodford	4	4	18	9	22	13
Arkoma Woodford			369	53	369	53
Other	216	169	244	124	460	293
East Region	654	534	14	10	668	544
Total	2,067	1,464	659	202	2,726	1,666

As of December 31, 2010, we did not own interests in any 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 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 the 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 of the properties or affect our carrying value of such 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.

Beginning in the third quarter of 2010 and through the present, as a result of pipeline constraints and the continuous increase in Williston Basin production, we are shipping a growing portion of our North region crude oil by rail car. We are using both manifest and unit train facilities for these shipments and anticipate that these shipments will continue and likely grow through the duration of 2011.

We have a strategic mix of gas transport, processing and sales arrangements for our natural gas production. Our natural gas production is sold at various points along the market chain from wellhead to points downstream under monthly interruptible packaged-volume deals, short-term seasonal packages, and long-term multi-year acreage dedication type contracts. All of our natural gas is sold at market based on published pricing. Our newest contracts allow us the flexibility to sell at the well or, with notice, take our gas in-kind , transport, process, and sell in the market area. Midstream natural gas gathering and processing companies are our primary transporters and purchasers.

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

For the year ended December 31, 2010, 2009 and 2008, crude oil sales to Marathon Crude Oil Company accounted for approximately 57%, 56% and 44% of our total revenues, respectively. No other purchasers accounted for more than 10% of our total crude oil and natural gas sales for 2010, 2009 and 2008. We believe that the loss of our largest purchaser would not have a material adverse effect on our operations, as there are a number of alternative crude oil purchasers in our producing regions.

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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.

Regulation of the Crude Oil and Natural Gas Industry

All of our operations are conducted onshore in the United States. The crude oil and natural gas industry in the United States is subject to various types of regulation at the federal, state and local levels. Laws, rules, regulations and other policy implementations affecting the crude oil and natural gas industry have been pervasive and are continuously reviewed for modification, including the imposition of new or increased requirements on us and other industry participants. Applicable laws and regulations affecting our industry and its members often carry substantial penalties for failure to comply. Such laws and regulations may have a significant effect on the exploration, development, production and sale of crude oil and natural gas. These laws and regulations increase the cost of doing business and, consequently, affect profitability. We believe that we are in substantial compliance with all laws and regulations currently applicable to our operations and that our continued compliance with existing requirements will not have a material adverse impact on us. However, because public policy changes affecting the crude oil and natural gas industry are commonplace and because existing laws and regulations may be amended or reinterpreted, we are unable to predict the future cost or impact of complying with such laws and regulations. We do not expect that any future legislative or regulatory initiatives will affect our operations in a manner materially different than they would affect our similarly situated competitors.

Following is a discussion of significant laws and regulations that may affect us in the areas in which we operate.

Regulation of Transportation and Sales 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. With regard to our physical sales of these energy commodities and derivative trading relating to these commodities, we are required to observe anti-market manipulation laws and related regulations enforced by the Federal Trade Commission (FTC) and the Commodity Futures Trading Commission (CFTC). See the discussion below of Other Federal Laws and Regulations Affecting Our Industry. Should we violate the anti-market manipulation laws and regulations, we could be subject to substantial penalties and related third-party damage claims by, among others, sellers, royalty owners and taxing authorities.

Our sales of crude oil are affected by the availability, terms and costs of transportation. The transportation of crude oil in common carrier pipelines is subject to rate and access regulation. The Federal Energy Regulatory Commission (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 many pipeline charges are today based on historical rates adjusted for inflation and other factors, and other charges may result from settlement rates agreed to by all shippers or market-based rates, which are permitted in certain circumstances.

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 the interstate and intrastate transportation rates that we pay are generally applicable to all comparable shippers, we believe that the regulation of crude oil transportation rates will not affect our operations in a way that materially differs from the effect on the operations of our competitors who are similarly situated.

Further, interstate and intrastate common carrier crude oil pipelines must provide service on an equitable basis. Under this 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.

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Federal government, primarily the FERC and its predecessor agency. 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, U.S. 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.

The 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 provide any assurance that the less stringent regulatory approach 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 prices at which we sell natural gas are not currently subject to federal rate regulation and, for the most part, are not subject to state regulation. However, with regard to our physical sales of natural gas and derivative trading relating to natural gas, we are required to observe anti-market manipulation laws and related regulations enforced by the FERC and the CFTC. See the discussion below of Other Federal Laws and Regulations Affecting Our Industry. Should we violate the anti-market manipulation laws and regulations, we could be subject to substantial penalties and related third party damage claims by, among others, sellers, royalty owners and taxing authorities. In addition, pursuant to FERC Order Nos. 704, 720 and 735, some of our operations may be required to submit reports to the FERC or post data on the internet regarding certain market transactions. See the discussion below of Other Federal Laws and Regulations Affecting Our Industry FERC Market Transparency and Reporting Rules.

Gathering service, which occurs upstream of jurisdictional transmission services, is regulated by the states onshore and in state waters. Although its policies on gathering systems have varied in the past, the 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. 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 natural gas 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 in a way that materially differs from the way it affects our competitors.

Intrastate natural gas transportation service is also subject to regulation by state regulatory agencies. 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. 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 a way that materially differs from the effect on the operations of our competitors.

Regulation of Production

The production of crude 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 crude oil and natural gas properties, the establishment of maximum allowable rates of production from crude oil and natural gas wells, the regulation of well spacing, and the plugging and abandonment of wells. The effect of these regulations is to limit the amount of crude 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 crude 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 crude oil and natural gas industry are subject to the same regulatory requirements and restrictions that affect our operations.

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Other Federal Laws and Regulations Affecting Our Industry

Dodd-Frank Wall Street Reform and Consumer Protection Act. On July 21, 2010, President Obama signed into law the Dodd-Frank Wall Street Reform and Consumer Protection Act (the Dodd-Frank Act), which, among other things, establishes federal oversight and regulation of the over-the-counter derivatives market and the entities, such as us, that participate in that market. Significant regulations are required to be promulgated by the SEC and the Commodity Futures Trading Commission within 360 days from the date of enactment to implement the new legislation. The new legislation, to the extent applicable to us or our derivative counterparties, may result in increased costs and cash collateral requirements for the types of derivative instruments we use to hedge and otherwise manage our financial and commercial risks related to fluctuations in commodity prices, and could have an adverse effect on our ability to hedge risks associated with our business. Many of the key concepts and processes under the Dodd-Frank Act are not defined and must be delineated by rules and regulations which have been and are being adopted by the applicable regulatory agencies. As a consequence, it is not possible at this time to predict the effects that the Dodd-Frank Act or the resulting rules and regulations may have on our hedging activities.

Energy Policy Act of 2005. On August 8, 2005, President Bush signed into law the Domenici-Barton Energy Policy Act of 2005 (EPAct 2005). The EPAct 2005 included a comprehensive compilation of tax incentives, authorized appropriations for grants and guaranteed loans, and made significant changes to the statutory framework affecting the energy industry. Among other matters, EPAct 2005 amended the Natural Gas Act (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 the FERC. On January 19, 2006, the FERC issued Order No. 670, which contained rules implementing the anti-market manipulation provision of EPAct 2005. The rules make it unlawful: (1) in connection with the purchase or sale of natural gas subject to the jurisdiction of the FERC, or the purchase or sale of transportation services subject to the jurisdiction of the 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. These anti-market manipulation rules do not apply to activities that relate only to intrastate or other non-jurisdictional sales or gathering, but do 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 FERC Order No. 704, which is described further below.

The EPAct 2005 also provided the FERC with additional civil penalty authority. The EPAct 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 increased the FERC s civil penalty authority under the Natural Gas Policy Act of 1978 (NGPA) from $5,000 per violation per day to $1,000,000 per violation per day. Under EPAct 2005, the 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 the FERC s NGA enforcement authority.

FERC Market Transparency and Reporting Rules. On December 26, 2007, the FERC issued a final rule, as amended on rehearing (Order No. 704) on the annual natural gas transaction reporting requirements. Under Order No. 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 required to report, on May 1 of each year, 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. Order No. 704 also requires market participants to indicate whether they report prices to any index publishers, and, if so, whether their reporting complies with the FERC s policy statement on price reporting. Failure to comply with these reporting requirements could subject us to enhanced civil penalty liability provided under EPAct 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 FTC. Under the EISA, the FTC issued its Petroleum Market Manipulation Rule (the 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.

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

Environmental, Health and Safety Regulation

General. Our operations are subject to stringent and complex federal, state, and local 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 Environmental Protection Agency (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 federal pipeline safety laws and comparable state and local requirements; (iv) the Clean Air Act and comparable state and local requirements, which establish pollution control requirements with respect to air emissions from our operations; (v) 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; (vi) 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; (vii) 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; (viii) the Safe Drinking Water Act and analogous state laws which impose requirements relating to our underground injection activities; (ix) 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; (x) 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 (xi) 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.

Climate change. Federal, state and local laws and regulations are increasingly being enacted to address concerns about the effects that carbon dioxide emissions and other identified greenhouse gases may have on the environment and climate worldwide. These effects are widely referred to as climate change. On December 15, 2009, the EPA 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 the warming of the earth s atmosphere and other climatic changes. These findings by the EPA have allowed the agency to implement regulations that restrict emissions of greenhouse gases under existing provisions of the federal Clean Air Act. In April 2010, the EPA finalized regulations that will require a reduction in emissions of greenhouse gases from motor vehicles beginning in 2011. In May 2010, the EPA finalized its tailoring rule , which sets forth criteria for determining which stationary sources are required to obtain permits to construct, modify or operate on account of, and to implement the best available control technology for, their greenhouse gases. In September 2009, the EPA finalized a rule that requires reporting of greenhouse gas emissions from specified large sources in the United States for emissions occurring in the prior calendar year. In November 2010, the EPA finalized its greenhouse gas reporting requirements for certain oil and gas production facilities that emit 25,000 metric tons or more of carbon dioxide equivalent per year. This rule became effective on December 30, 2010 and requires reporting of greenhouse gas emissions to the EPA by March 2012 for emissions during 2011, and annually thereafter. Also, legislation has been proposed in both the U.S. House of Representatives and Senate that would establish a cap-and-trade program to reduce U.S. emissions of greenhouse gases, including carbon dioxide and methane. Under these proposals, the EPA would issue or sell 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 such legislation, if adopted, would be to impose increasing costs on the combustion of carbon-based fuels such as crude oil, refined petroleum products, and natural gas.

As a crude oil and natural gas company, the debate on climate change is relevant to our operations because the equipment we use to explore for, develop and produce crude oil and natural gas emits greenhouse gases. Additionally, the combustion of carbon-based fuels, such as the crude oil and natural gas that we sell, emits carbon dioxide and other greenhouse gases. Thus, any one of the federal, state or local climate change initiatives could have a material adverse effect on our business. The climate change laws and regulations could adversely affect demand for the crude oil and natural gas that we produce by stimulating demand for alternative forms of energy that do not rely on the combustion of fossil fuels. Although our compliance with any regulation of greenhouse gases may result in increased compliance and operating costs, we do not expect the costs to comply with the currently applicable regulations to be material. It is not possible at this time to estimate the costs or operational impacts we could experience to comply with new legislative or regulatory developments. We do not anticipate that we would be impacted by the climate change initiatives to any greater degree than other similar competitors.

Hydraulic fracturing. The U.S. Congress is considering legislation to amend the federal Safe Drinking Water Act to remove the exemption for hydraulic fracturing operations and require reporting and disclosure of chemicals used by the crude oil and natural gas industry in the hydraulic fracturing process, including, for example, the Fracturing Responsibility and Awareness of Chemicals Act of 2009. Hydraulic fracturing involves the injection of water, sand and chemicals under pressure into rock formations to stimulate crude oil and natural gas production. Sponsors of bills pending before the U.S. Congress have asserted that chemicals used in the fracturing process could adversely affect drinking water supplies. These bills, if adopted, could increase the possibility of litigation and establish an additional level of regulation at the federal level that could prohibit hydraulic fracturing or could lead to operational delays or increased operating costs and could result in additional regulatory burdens, making it more difficult to perform hydraulic fracturing and increasing our costs of compliance. Compliance, or the consequences of any failure to comply by us, could have a material adverse effect on our financial condition and results of operations. However, at this time it is not possible to estimate the potential impact on our business that may arise if federal or state legislation is enacted into law. In addition, in March 2010 the EPA announced its intention to conduct a comprehensive research study on the potential adverse impacts that hydraulic fracturing may have on water quality and public health. Thus, even if the pending legislation is not adopted by the U.S. Congress, the EPA study, depending on its results, could spur further initiatives to regulate hydraulic fracturing under the Safe Drinking Water Act.

Employees

As of December 31, 2010, we employed 493 people, including 272 employees in drilling and production, 75 in financial and accounting, 49 in land, 26 in exploration, 15 in reservoir engineering, 42 in administrative and 14 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.

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, 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 web site that contains reports, proxy and information statements, and other information regarding issuers that file electronically with the SEC. The address of the SEC s website 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.

We are subject to certain risks and hazards due to the nature of the business activities we conduct. The risks discussed below, any of which could materially and adversely affect our business, financial condition, cash flows, and results of operations, are not the only risks we face. We may experience additional risks and uncertainties not currently known to us; or, as a result of developments occurring in the future, conditions that we currently deem to be immaterial may also materially and adversely affect our business, financial condition, cash flows, and results of operations.

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 needs 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 recent worldwide economic recession 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 prices in excess of $90 per Bbl in 2010. Natural gas prices declined from over $13 per Mcf in mid-2008 to approximately $4 per Mcf in February 2009 and remained at depressed levels throughout 2010.

Lower crude oil and natural gas prices could reduce our cash flows available for capital expenditures, repayment of indebtedness and other corporate purposes; result in a decrease in the borrowing base under our revolving credit facility or otherwise limit our ability to borrow money or raise additional capital; and 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, 78% of our production during the fourth quarter of 2010 was from the North region. As a result of this concentration, we are significantly exposed to the impact of regional supply and demand factors, transportation capacity constraints, curtailment of production or interruption of transportation of crude oil and natural gas 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 was $9.38 per Bbl for our North region properties for the year ended December 31, 2010, whereas the difference between the average NYMEX crude oil price and our average realized crude oil price was $9.02 per Bbl on a Company-wide basis for the year ended December 31, 2010.

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. In 2010, we had $1.24 billion of capital and exploration expenditures. Our capital expenditures for 2011 are budgeted to be approximately $1.36 billion with $1.23 billion allocated for drilling and completion operations. To date, these capital expenditures have been financed with cash generated by operations, borrowings under our revolving credit facility and the issuance of senior notes. The actual amount and timing of our future capital expenditures may differ materially from our estimates as a result of, among other things, commodity prices, actual drilling results, the availability of drilling rigs and other services and equipment, and regulatory, technological and competitive developments. Continued improvement in commodity prices may result in an increase in our actual capital expenditures. Conversely, a significant decline in commodity 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 our common stock.

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

- our proved reserves;
- the volume of crude oil and natural gas we are able to produce and sell 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. Our cost of drilling, completing and operating wells is often uncertain before drilling commences.

Further, many factors may curtail, delay or cancel our scheduled drilling projects, including the following:

- delays imposed by or resulting from compliance with regulatory requirements;
- pressure or irregularities in geological formations;

- shortages of or delays in obtaining equipment and qualified personnel;
- equipment failures or accidents;
- adverse weather conditions, such as blizzards and ice storms;
- reductions in crude oil and natural gas prices;
- limited availability of financing at acceptable rates;
- title problems;
- limitations in transportation capacity or in the market for crude oil and natural gas; and
- adverse governmental regulations.

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, 2010.

In order to prepare our estimates, we must project production rates and the amount 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 crude 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 crude 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 at year-end. In accordance with the SEC requirements that went into effect in 2009, 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 commodity prices for the preceding twelve months. Actual future net revenues from our crude oil and natural gas properties will be affected by factors such as:

- actual prices we receive for crude oil and natural gas;
- actual cost and timing 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 crude 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 crude oil and natural gas industry in general.

Actual future prices and costs may differ materially from those used in the present value estimate. If crude oil prices decline by $10.00 per Bbl, then our PV-10 as of December 31, 2010 would decrease approximately $849 million. If natural gas prices decline by $1.00 per Mcf, then our PV-10 as of December 31, 2010 would decrease approximately $392 million.

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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 values 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 values 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 exploration, exploitation and development 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 materially 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.

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;
- 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 economically producible quantities.

Prospects that we decide to drill that do not yield crude oil or natural gas in economically producible 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 producible. 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 economically producible quantities. We cannot assure you that the analogies we draw from available data from other wells, more fully explored prospects or producing fields will be applicable to our drilling prospects.

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

Our management has specifically identified and scheduled drilling locations as an estimation of our future multi-year drilling activities on our existing acreage. These drilling locations represent a significant part of our growth strategy. Our ability to drill and develop these locations depends on a number of uncertainties, including crude oil and natural gas prices, the availability of capital, costs, drilling results, regulatory approvals and other factors. 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. Unless we are able to renew expired leases, any proved undeveloped reserves associated with such leases will be removed from our proved reserves. As of December 31, 2010, we had leases representing 321,579 net acres expiring in 2011, 249,277 net acres expiring in 2012, and 423,846 net acres expiring in 2013. 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 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 and production 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 and local 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 and local 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 *Item 1. Business 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 are not able to recover the resulting costs through insurance or increased revenues, our business, financial condition and results of operations could be adversely affected.

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

On December 15, 2009, the EPA 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 have allowed the agency to implement regulations that restrict emissions of greenhouse gases under existing provisions of the federal Clean Air Act. In April 2010, the EPA finalized regulations that will require a reduction in emissions of greenhouse gases from motor vehicles beginning in 2011. In May 2010, the EPA finalized its tailoring rule , which sets forth criteria for determining which stationary sources are required to obtain permits to construct, modify or operate on account of, and to implement the best available control technology for, their greenhouse gas emissions pursuant to the Clean Air Act Prevention of Significant Deterioration and Title V operating permit programs. Under the tailoring rule, permitting requirements will be phased in through successive steps that expand the scope of covered sources over time. In September 2009, the EPA finalized a rule that requires reporting of greenhouse gas emissions from specified large sources in the United States for emissions occurring in the prior calendar year. In November 2010, the EPA finalized its greenhouse gas reporting requirements for certain oil and gas production facilities that emit 25,000 metric tons or more of carbon dioxide equivalent per year. This rule became effective on December 30, 2010 and requires reporting of greenhouse gas emissions to the EPA by March 2012 for emissions during 2011, and annually thereafter. Some of our facilities may be subject to the reporting rules for the oil and gas industry, and may also be covered by subsequent phases of the tailoring rule or other rulemakings.

Legislation has been proposed in both the U.S. House of Representatives and Senate that would establish a cap-and-trade program to reduce U.S. emissions of greenhouse gases, including carbon dioxide and methane. Under these proposals, the EPA would issue or sell 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 such legislation, if adopted, would be to impose increasing costs on the combustion of carbon-based fuels such as crude oil, refined petroleum products, and natural gas. 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 or if Congress may act on climate change legislation, any future federal laws or implementing regulations that may be adopted to address greenhouse gas emissions could require us to incur increased operating costs.

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 federal, regional, state or local climate change regulatory or legislative initiatives, or related litigation (including pending common law nuisance suits against various companies relating to greenhouse gases), could have a material adverse effect on our business, financial condition and results of operations. These laws and regulations could also adversely affect demand for the crude oil, natural gas and NGLs we produce, including by increasing their cost. In addition, these laws and regulations could drive down demand for our products by stimulating demand for alternative forms of energy that do not rely on combustion of fossil fuels (such as oil, natural gas and NGLs), which is a major source of greenhouse gas emissions.

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.

Federal and state legislation and regulatory initiatives relating to hydraulic fracturing could result in increased costs and additional operating restrictions or delays and inability to book future reserves.

Legislation has been proposed in Congress to amend the federal Safe Drinking Water Act to require the disclosure of chemicals used by the oil and natural gas industry in the hydraulic fracturing process. Hydraulic fracturing involves the injection of water, sand and chemicals under pressure into rock formations to stimulate oil and natural gas production. We engage third parties to provide hydraulic fracturing or other well stimulation services to us in connection with several wells or proposed wells for which we are the operator. Sponsors of bills currently pending in Congress have asserted that chemicals used in the fracturing process may be adversely impacting drinking water supplies. The proposed legislation would require the reporting and public disclosure of chemicals used in the fracturing process, which could make it easier for third parties opposing the hydraulic fracturing process to initiate legal proceedings based on allegations that specific chemicals used in the fracturing process are impairing groundwater or causing other damage. These bills, if adopted, could establish an additional level of regulation at the federal or state level that could prohibit hydraulic fracturing or could lead to operational delays or increased operating costs and could result in additional regulatory burdens that could make it more difficult to perform hydraulic fracturing and increase our costs of compliance and doing business. Certain states and other agencies have adopted or are considering similar disclosure legislation, moratoria or enforcement initiatives relating to hydraulic fracturing. These legislative and regulatory initiatives, to the extent they are adopted or continue, could prohibit or limit our ability to develop our crude oil and natural gas properties located in unconventional formations, which would adversely affect our ability to access, develop and book reserves in the future.

In March 2010, the United States Environmental Protection Agency announced that it would conduct a wide-ranging study on the effects of hydraulic fracturing on human health and the environment. The agency also announced that one of its enforcement initiatives for 2011 to 2013 would be to focus on environmental compliance by the energy extraction sector, and has already commenced one potential enforcement matter in Texas**.** This study and enforcement initiative could result in additional regulatory scrutiny that could make it difficult to perform hydraulic fracturing and increase our costs of compliance and doing business.

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

The FERC, under the EPAct 2005, and the FTC, under the Independence and Security Act of 2007, may impose penalties for current violations of anti-market manipulation rules for natural gas, crude oil and petroleum products of up to $1,000,000 per day for each violation. While our systems have not been regulated by the FERC as a natural gas company under the NGA, the FERC has adopted regulations that may subject certain of our otherwise non-FERC jurisdictional facilities to the 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 the FERC from time to time. The FTC has also adopted anti-market manipulation rules that apply to our sales and trading of crude oil and petroleum products. Failure to comply with any of these regulations in the future could subject us to civil penalty liability, as well as the disgorgement of profits and third-party claims.

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.

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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 in recent 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 our 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, Colorado 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.

We have limited control over the activities on properties we do not operate.

Some of the properties in which we have an interest are operated by other companies and involve third-party working interest owners. As a result, we have limited ability to influence or control the operation or future development of such properties, including compliance with environmental, safety and other regulations, or the amount of capital expenditures that we will be required to fund with respect to such properties. Moreover, we are dependent on the other working interest owners of such projects to fund their contractual share of the capital expenditures of such projects. These limitations and our dependence on the operator and other working interest owners for these projects could cause us to incur unexpected future costs and materially and adversely affect our financial condition and results of operations.

Our revolving credit facility and the indentures for our senior notes contain certain covenants and 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 and the indentures for our senior notes include certain covenants and restrictions 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 a 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.

The indentures for our outstanding senior notes limit our ability and the ability of our restricted subsidiaries to:

- incur, assume or guarantee additional indebtedness or issue redeemable stock;
- pay dividends on stock, repurchase stock or redeem subordinated debt;
- make certain investments;
- enter into certain transactions with affiliates;
- create certain liens on our assets;
- sell or otherwise dispose of certain assets, including capital stock of subsidiaries;

- restrict dividends, loans or other asset transfers from our restricted subsidiaries;
- enter into new lines of business; and
- consolidate with or merge with or into, or sell all or substantially all of our properties to another person.

Our revolving credit facility also requires us to maintain certain financial ratios, such as leverage ratios.

The restrictive covenants in our revolving credit facility and the senior note indentures 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 or senior note indentures 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 or senior note indentures, in which case, depending on the actions taken by the lenders or trustee thereunder or their successors or assignees, such lenders or trustees could elect to declare all amounts outstanding thereunder, together with accrued interest, to be due and payable. If we were unable to repay such borrowings or interest under our revolving credit facility, 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 ratings. 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 18, 2011, outstanding borrowings under our revolving credit facility were $95.0 million and the impact of a 1% increase in interest rates on this amount of debt would result in increased annual interest expense of approximately $1.0 million and a $0.6 million decrease in our annual 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.

Volatility in the financial markets or in macro-economic factors could adversely 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 a deterioration of the capital and credit markets and our borrowing base.

Volatility in U.S. and global financial and equity markets, including market disruptions, limited liquidity, and interest rate volatility, may increase our cost of financing. Further, economic uncertainty could reduce the demand for crude oil and natural gas and put downward pressure on the prices for crude oil and natural gas, which would negatively impact our revenues and cash flows. Historically, we have used our cash flows from operations, borrowings under our revolving credit facility and capital market transactions to fund our capital expenditures.

We have an existing revolving credit facility with lender commitments totaling $750 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 our borrowing base in the future and, in such case, we could be required to repay any indebtedness in excess of the borrowing base.

Due to these factors, we cannot be certain that funding, if needed, will be available to the extent required and on terms we find acceptable. 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 financial condition and results of operations.

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 ($269.5 million at December 31, 2010) and the sale of our crude oil and natural gas production ($213.3 million in receivables at December 31, 2010), which we market to energy marketing companies, refineries and affiliates. Joint interest receivables arise from billing entities who own partial interest in the wells we operate. These entities participate in our wells primarily based on their ownership in leases on which we wish to drill. We can do very little to choose who participates in our wells. We are also subject to credit risk due to concentration of our crude oil and natural gas receivables with several significant customers. The largest purchaser of our crude oil and natural gas during the year ended December 31, 2010 accounted for 57% 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 condition and results of operations.

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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 enter into derivative instruments for a portion of our crude oil and/or natural gas production, including collars and fixed price swaps. See *Item 7. Management s Discussion and Analysis of Financial Condition and Results of Operations Crude Oil and Natural Gas Hedging* and *Item 8. 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 the fair value of our derivative instruments.

Derivative instruments 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 contractual obligations; or
- there is an increase in the differential between the underlying price in the derivative instrument and actual prices received.

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

Our Chairman and Chief Executive Officer owns approximately 72.6% 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 18, 2011, Harold G. Hamm, our Chairman and Chief Executive Officer, beneficially owned 123,753,708 shares of our outstanding common stock representing approximately 72.6% of our outstanding common shares. As a result, Mr. Hamm is 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 operating costs and have a material adverse effect on our financial condition and results of operations. For example, Congress is 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 regulation. If such legislation is adopted, it could result in, among other items, additional regulation of and restrictions on hydraulic fracturing of wells, and additional regulation of private energy commodity derivative and hedging activities. These and other potential laws and regulations could increase our 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 and results of operations.

Certain federal income tax deductions currently available with respect to oil and gas exploration and development may be eliminated as a result of future legislation.

Among the changes contained in President Obama s fiscal year 2012 budget proposal, released by the White House on February 14, 2011, is the elimination or deferral of certain key U.S. federal income tax deductions currently available to oil and gas exploration and production companies. Such proposed changes include, but are not limited to, (i) the repeal of the percentage depletion allowance for oil and gas properties; (ii) the elimination of current deductions for intangible drilling and development costs; (iii) the elimination of the deduction for certain U.S. production activities; and (iv) an extension of the amortization period for certain geological and geophysical expenditures. Recently, members of the U.S. Congress have considered similar changes to the existing federal income tax laws that affect oil and gas exploration and production companies, which, if enacted, would negatively affect our financial condition and results of operations. The passage of any legislation as a result of the budget proposal or any other similar change in U.S. federal income tax law could eliminate or defer certain tax deductions within the industry that are currently available with respect to oil and gas exploration and development, and any such change could negatively affect our financial condition and results of operations.

Potential regulations under the Dodd-Frank Act regarding derivatives could have an adverse effect on our ability to use derivative instruments to reduce the effect of commodity price risk and other risks associated with our business.

We use derivative instruments to manage our commodity price risk. In 2010, Congress adopted the Dodd-Frank Wall Street Reform and Consumer Protection Act (HR 4173), which, among other provisions, establishes federal oversight and regulation of the over-the-counter derivatives market and entities, such as us, that participate in that market. The new legislation was signed into law by President Obama on July 21, 2010 and requires the Commodities Futures Trading Commission (the CFTC) and the SEC to promulgate rules and regulations implementing the new legislation within 360 days from the date of enactment. The CFTC has also proposed regulations to set position limits for certain futures and option contracts in the major energy markets, although it is not possible at this time to predict whether or when the CFTC will adopt those rules or include comparable provisions in its rulemaking under the new legislation. The financial reform legislation may also require us to comply with margin requirements and with certain clearing and trade-execution requirements in connection with our derivative activities, although the application of those provisions to us is uncertain at this time. The financial reform legislation may also require the counterparties to our derivative instruments to spin off some of their derivatives activities to a separate entity, which may not be as creditworthy as the current counterparty.

The new legislation and any new regulations could significantly increase the cost of derivative contracts (including through requirements to post collateral, which could adversely affect our available liquidity), materially alter the terms of derivative contracts, reduce the availability of derivatives to protect against risks we encounter, reduce our ability to monetize or restructure existing derivative contracts, and increase our exposure to less creditworthy counterparties. If we reduce our use of derivatives as a result of the legislation and regulations, our results of operations may become more volatile and our cash flows may be less predictable. Finally, the legislation was intended, in part, to reduce the volatility of crude oil and natural gas prices, which some legislators attributed to speculative trading in derivatives and commodity instruments related to crude oil and natural gas. Our revenues could therefore be adversely affected if a consequence of the legislation and regulations is to lower commodity prices. Any of these consequences could have a material adverse effect on our financial position and results of operations.

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;
- future development costs, operating costs and property taxes; 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.

Item 1B. Unresolved Staff Comments

There were no unresolved Securities and Exchange Commission staff comments at December 31, 2010.

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

On November 4, 2010, a putative class action was filed against the Company alleging the Company improperly deducted post-production costs from royalties paid to plaintiffs and other royalty interest owners from oil and gas wells located in Oklahoma. The plaintiffs seek recovery of compensatory damages, interest, punitive damages and attorney fees on behalf of the putative class. The Company has responded to the petition and denied the allegations and raised a number of affirmative defenses. The action is in very preliminary stages and no discovery has been conducted. As such, the Company is not able to estimate what impact, if any, the action will have on its financial condition, results of operations or cash flows.

The Company is involved in various other legal proceedings such as commercial disputes, claims from royalty and surface owners, property damage claims, personal injury claims and similar matters. While the outcome of these legal matters cannot be predicted with certainty, the Company does not expect them to have a material adverse effect on its financial condition, results of operations or cash flows.

Item 4. (Removed and Reserved)

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Part II

Item 5. Market for Registrant s Common Equity, Related Shareholder Matters and Issuer Purchases of Equity Securities

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.

	2010 Quarter ended				2009 Quarter ended			
	March 31	June 30	September 30	December 31	March 31	June 30	September 30	December 31
High	$ 46.18	$ 52.53	$ 48.65	$ 59.98	$ 26.97	$ 34.41	$ 44.31	$ 47.27
Low	36.27	39.35	38.23	45.00	13.84	20.00	22.33	36.25
Cash Dividend								

Our senior notes restrict the payment of dividends under certain circumstances and we do not anticipate paying any cash dividends on our common stock in the foreseeable future. As of February 18, 2011, the number of record holders of our common stock was 72. Management believes, after inquiry, that the number of beneficial owners of our common stock is approximately 20,600. On February 18, 2011, the last reported sales price of our Common Stock, as reported on the NYSE, was $63.84 per share. The following table summarizes our purchases of our common stock during the quarter ended December 31, 2010:

Period	Total number of shares purchased (1)	Average price paid per share (2)	Total number of shares purchased as part of publicly announced plans or programs	Maximum number of shares that may yet be purchased under the plans or program (3)
October 1, 2010 to October 31, 2010	53,734	$ 48.65		
November 1, 2010 to November 30, 2010	24,897	$ 49.92		
December 1, 2010 to December 31, 2010	726	$ 57.91		
Total	79,357	$ 49.13		

(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. 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.

Performance Graph

The following performance graph compares the yearly percentage change in the cumulative total shareholder return on our common stock with the cumulative total returns of the Standard & Poor s 500 Index (S&P 500 Index) and the group of companies in our peer group as outlined below. 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 those 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 was 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.

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In years prior to 2010, our peer group was comprised of the following companies:

- Bill Barrett Corporation
- Denbury Resources Inc.
- Encore Acquisition Company
- Quicksilver Resources Inc.
- Range Resources Corporation
- SM Energy Company (formerly St. Mary Land and Exploration Company)
- Southwestern Energy Company

In March 2010, Encore Acquisition Company was acquired by Denbury Resources Inc. and ceased being a stand-alone publicly traded entity. As a result, Encore Acquisition Company was removed from our peer group in 2010. Further, in 2010 our peer group was expanded to include the additional companies shown below. These companies have historically been included in our executive compensation survey group and proxy statement filings for 2007, 2008 and 2009 and are now being included herein so that our peer group used in this Annual Report on Form 10-K is consistent with the peer group used in our proxy statement disclosures. The historical peers reflected above and the additional peers below were selected because they are publicly traded crude oil and natural gas exploration and production companies similar in size and operations to us.

- Cabot Oil & Gas Corporation
- Comstock Resources, Inc.
- EXCO Resources, Inc.
- Forest Oil Corporation
- Petrohawk Energy Corporation
- Plains Exploration & Production Company

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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, 2006 through 2010, 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 *Item 7. Management s Discussion and Analysis of Financial Condition and Results of Operations* and our historical consolidated financial statements and related notes included elsewhere in this report. The selected historical consolidated results are not necessarily indicative of results to be expected in future periods.

	YEAR ENDED DECEMBER 31,				
	2010	2009	2008	2007	2006
Statement of Income					
(in thousands, except per share data)					
Crude oil and natural gas sales	$ 948,524	$ 610,698	$ 939,906	$ 606,514	$ 468,602
Losses on derivative instruments, net[(1)]	(130,762)	(1,520)	(7,966)	(44,869)	
Total revenues	839,065	626,211	960,490	582,215	483,652
Income from continuing operations	168,255	71,338	320,950	28,580	253,088
Net Income	168,255	71,338	320,950	28,580	253,088
Basic earnings per share:					
From continuing operations	$ 1.00	$ 0.42	$ 1.91	$ 0.17	$ 1.60
Net income per share	$ 1.00	$ 0.42	$ 1.91	$ 0.17	$ 1.60
Shares used in basic earnings per share	168,985	168,559	168,087	164,059	158,114
Diluted earnings per share:					
From continuing operations	$ 0.99	$ 0.42	$ 1.89	$ 0.17	$ 1.59
Net income per share	$ 0.99	$ 0.42	$ 1.89	$ 0.17	$ 1.59
Shares used in diluted earnings per share	169,779	169,529	169,392	165,422	159,665
Pro forma C-corporation[(2)]					
Pro forma income from continuing operations				$ 184,002	$ 156,833
Pro forma net income				184,002	156,833
Pro forma basic earnings per share				1.12	0.97
Pro forma diluted earnings per share				1.11	0.96
Production					
Crude oil (MBbl)[(3)]	11,820	10,022	9,147	8,699	7,480
Natural gas (MMcf)	23,943	21,606	17,151	11,534	9,225
Crude oil equivalents (MBoe)	15,811	13,623	12,006	10,621	9,018
Average sales prices[(4)]					
Crude oil ($/Bbl)	$ 70.69	$ 54.44	$ 88.87	$ 63.55	$ 55.30
Natural gas ($/Mcf)	4.49	3.22	6.90	5.87	6.08
Crude oil equivalents ($/Boe)	59.70	45.10	77.66	58.31	52.09
Average costs per Boe ($/Boe)[(4)]					
Production expenses	$ 5.87	$ 6.89	$ 8.40	$ 7.35	$ 6.99
Production taxes and other expenses	4.82	3.37	4.84	3.13	2.48
Depreciation, depletion, amortization and accretion	15.33	15.34	12.30	9.00	7.27
General and administrative expenses	3.09	3.03	2.95	3.15	3.45
Proved reserves at December 31					
Crude oil (MBbl)	224,784	173,280	106,239	104,145	98,038
Natural gas (MMcf)	839,568	504,080	318,138	182,819	121,865
Crude oil equivalents (MBoe)	364,712	257,293	159,262	134,615	118,349
Other financial data (in thousands)					
Net cash provided by operations	653,167	372,986	719,915	390,648	417,041
Net cash used in investing	(1,039,416)	(499,822)	(927,617)	(483,498)	(324,523)
Net cash provided by (used in) financing	379,943	135,829	204,170	94,568	(91,451)
EBITDAX[(5)]	810,877	450,648	757,708	469,885	372,115
Capital expenditures	1,237,189	433,991	988,593	525,677	326,579
Cash dividends per share	$	$	$	$ 0.33	$ 0.55

Balance sheet data at December 31 (in thousands)					
Total assets	$ 3,591,785	$ 2,314,927	$ 2,215,879	$ 1,365,173	$ 858,929
Long-term debt, including current maturities	925,991	523,524	376,400	165,000	140,000
Shareholders equity	1,208,155	1,030,279	948,708	623,132	490,461

(1) Derivative instruments are not accounted for as hedges and, therefore, realized and unrealized changes in fair value of the instruments are shown separately from crude oil and natural gas sales. The amounts above include unrealized non-cash mark-to-market losses on derivative instruments of $166.2 million, $2.1 million, and $26.7 million for the years ended December 31, 2010, 2009 and 2007, respectively. There were no unrealized gains or losses on derivative instruments for the years ended December 31, 2008 and 2006.

(2) Prior to our initial public offering on May 14, 2007, we were a subchapter S corporation and income taxes were payable by our shareholders. As a result, there was a minimal provision for income taxes for the periods ended December 31, 2006 and prior. In connection with our initial public offering, we

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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. For the year 2010, crude oil sales volumes were 78 MBbls more than crude oil production volumes. 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 sales prices and average costs per Boe have been computed using sales volumes and exclude any effect of derivative transactions.

(5) EBITDAX represents earnings before interest expense, income taxes, depreciation, depletion, amortization and accretion, property impairments, exploration expenses, unrealized derivative gains and losses and non-cash equity compensation expense. EBITDAX is not a measure of net income or cash flows as determined by generally accepted accounting principles (GAAP). A reconciliation of net income to EBITDAX is provided in *Item 7. Management s Discussion and Analysis of Financial Condition and Results of Operations Non-GAAP Financial Measures*.

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

The following discussion and analysis 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 crude oil and natural gas reserve information, please see *Item 1. Business Crude Oil and Natural Gas Operations.* The following discussion and analysis includes forward-looking statements and should be read in conjunction with *Item 1A. Risk Factors* in this report, along with *Cautionary Statement Regarding Forward-Looking Statements* at the beginning of this report, for information about the risks and uncertainties that could cause our actual results to be materially different than our forward-looking statements.

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. The North region consists of properties north of Kansas and west of the Mississippi river and includes North Dakota Bakken, Montana Bakken, the Red River units and the Niobrara play in Colorado and Wyoming. The South region includes Kansas and all properties south of Kansas and west of the Mississippi river including the Arkoma Woodford and Anadarko Woodford plays in Oklahoma. The East region contains properties east of the Mississippi river including the Illinois Basin and Michigan.

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 allow us to economically develop and produce crude oil and natural gas reserves from unconventional formations. We derive the majority of our operating income and cash flows from the sale of crude oil and natural gas. We expect that growth in our revenues and operating income will primarily depend on product prices and our ability to increase our crude oil and natural gas production. In recent months and years, there has been significant volatility in crude oil and natural gas prices due to a variety of factors we cannot control or predict, including political and economic events, weather conditions, and competition from other energy sources. These factors impact supply and demand for crude oil and natural gas, which affects crude oil and natural gas prices. In addition, the prices we realize for our crude oil and natural gas production are affected by location differences in market prices.

Crude oil comprised 62% of our 364.7 MMBoe of estimated proved reserves as of December 31, 2010 and 75% of our 15,811 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 88% of our PV-10 and 69% of our 2,726 gross wells as of December 31, 2010. By controlling operations, we are able to more effectively manage the costs 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, 2010, we added 253,334 MBoe of proved reserves through extensions and discoveries, compared to 2,603 MBoe added through acquisitions. During this period, our production increased from 12,006 MBoe in 2008 to 15,811 MBoe in 2010. An aspect of our business strategy has been to acquire large undeveloped acreage positions in new or developing resource plays. As of December 31, 2010, we held 2,344,148 gross (1,370,435 net) undeveloped acres, including 669,560 net undeveloped acres in the Bakken field in Montana and North Dakota and 265,119 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.

For the year ended December 31, 2010, our crude oil and natural gas production increased to 15,811 MBoe (43,318 Boe per day), an increase of 16% from the year ended December 31, 2009. The increase in 2010 production primarily resulted from an increase in production from our North Dakota Bakken field and Anadarko Woodford play in Oklahoma. Crude oil and natural gas revenues for 2010 increased by 55% to $948.5 million due to a 32% increase in realized commodity prices along with increased production compared to 2009. Our realized price per Boe increased $14.60 to $59.70 for 2010 compared to 2009. 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. Crude oil sales volumes were 78 MBbls more than crude oil production for the year ended December 31, 2010 and crude oil sales volumes were 82 MBbls less than crude oil production for the same period in 2009. Our cash flows from operating activities for the year ended December 31, 2010 were $653.2 million, an increase of $280.2 million from $373.0 million provided by our operating activities during the comparable 2009 period. The increase in operating cash flows was primarily due to increased crude oil and natural gas revenues as a result of higher commodity prices and sales volumes. During the year ended December 31, 2010, we invested $1.24 billion (including increased accruals for capital expenditures of $148.0 million and $5.8 million of seismic costs) in our capital program, concentrating mainly in the Bakken field, the Oklahoma Woodford play, and the Red River units.

In October 2010, our Board of Directors approved a 2011 capital expenditures budget of $1.36 billion, which will focus primarily on increased development in the Bakken shale of North Dakota and the Anadarko Woodford shale in western Oklahoma. We expect our cash flows from operations and the availability under our revolving credit facility will be sufficient to meet our capital expenditure needs.

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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 operating highlights for each of the three years ended December 31, 2010.

	Year ended December 31,		
	2010	2009	2008
Average daily production:			
Crude oil (Bbl per day)	32,385	27,459	24,993
Natural gas (Mcf per day)	65,598	59,194	46,861
Crude oil equivalents (Boe per day)	43,318	37,324	32,803
Average sales prices:(1)			
Crude oil ($/Bbl)	$ 70.69	$ 54.44	$ 88.87
Natural gas ($/Mcf)	4.49	3.22	6.90
Crude oil equivalents ($/Boe)	59.70	45.10	77.66
Production expenses ($/Boe)(1)	5.87	6.89	8.40
General and administrative expenses ($/Boe)(1) (2)	3.09	3.03	2.95
Net income (in thousands)	168,255	71,338	320,950
Diluted net income per share	0.99	0.42	1.89
EBITDAX (in thousands)(3)	810,877	450,648	757,708

(1) Average sales prices and per unit expenses have been calculated using sales volumes and exclude any effect of derivative transactions.
(2) General and administrative expense ($/Boe) includes non-cash equity compensation expense of $0.74 per Boe, $0.84 per Boe, and $0.75 per Boe for the years ended December 31, 2010, 2009 and 2008, respectively.
(3) EBITDAX represents earnings before interest expense, income taxes, depreciation, depletion, amortization and accretion, property impairments, exploration expenses, unrealized derivative gains and losses and non-cash equity 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 *Non-GAAP Financial Measures* below.

Results of Operations

The following table presents selected financial and operating information for each of the three years ended December 31, 2010:

	Year Ended December 31,		
(in thousands, except sales price data)	**2010**	**2009**	**2008**
Crude oil and natural gas sales	$ 948,524	$ 610,698	$ 939,906
Loss on mark-to-market derivative instruments, net(1)	(130,762)	(1,520)	(7,966)
Total revenues	839,065	626,211	960,490
Operating costs and expenses(2)	528,744	493,923	431,167
Other expenses, net	51,854	22,280	10,793
Income before income taxes	258,467	110,008	518,530
Provision for income taxes	90,212	38,670	197,580
Net income	$ 168,255	$ 71,338	$ 320,950
Production volumes:			
Crude oil (MBbl)(3)	11,820	10,022	9,147
Natural gas (MMcf)	23,943	21,606	17,151
Crude oil equivalents (MBoe)	15,811	13,623	12,006
Sales volumes:			
Crude oil (MBbl)(3)	11,898	9,940	9,244

Natural gas (MMcf)	23,943	21,606	17,151
Crude oil equivalents (MBoe)	15,889	13,541	12,103
Average sales prices:(4)			
Crude oil ($/Bbl)	$ 70.69	$ 54.44	$ 88.87
Natural gas ($/Mcf)	$ 4.49	$ 3.22	$ 6.90
Crude oil equivalents ($/Boe)	$ 59.70	$ 45.10	$ 77.66

(1) Amounts include unrealized non-cash mark-to-market losses on derivative instruments of $166.2 million and $2.1 million for the years ended December 31, 2010 and 2009, respectively. There were no unrealized gains or losses on derivative instruments for the year ended December 31, 2008.

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(2) Net of gain on sale of assets of $29.6 million, $0.7 million and $0.9 million for the years ended December 31, 2010, 2009 and 2008, respectively. In June 2010, we sold certain non-strategic leaseholds located in DeSoto Parish, Louisiana to a third party with an effective date of June 18, 2010. Total cash proceeds amounted to $35.4 million. In connection with the sale, we recognized a pre-tax gain of $31.7 million. The sale involved undeveloped acreage with no proved reserves and no production or revenues.
(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. Crude oil sales volumes were 78 MBbls more than crude oil production for the year ended December 31, 2010, 82 MBbls less than crude oil production for the year ended December 31, 2009 and 97 MBbls more than crude oil production for the year ended December 31, 2008.
(4) Average sales prices have been calculated using sales volumes and exclude any effect of derivative transactions.

Year ended December 31, 2010 compared to the year ended December 31, 2009

Production

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

	Year Ended December 31, 2010		2009			
	Volume	Percent	Volume	Percent	Volume increase	Percent increase
Crude oil (MBbl)	11,820	75%	10,022	74%	1,798	18%
Natural gas (MMcf)	23,943	25%	21,606	26%	2,337	11%
Total (MBoe)	15,811	100%	13,623	100%	2,188	16%

	Year Ended December 31, 2010		2009			
	MBoe	Percent	MBoe	Percent	Volume increase (decrease)	Percent increase (decrease)
North	12,431	79%	10,314	76%	2,117	21%
South	2,915	18%	2,784	20%	131	5%
East	465	3%	525	4%	(60)	(11)%
Total (MBoe)	15,811	100%	13,623	100%	2,188	16%

Crude oil production volumes increased 18% during the year ended December 31, 2010 compared to the year ended December 31, 2009. Production increases in the North Dakota Bakken field, Red River units, and the Oklahoma Woodford play contributed incremental production volumes in 2010 of 2,262 MBbls in excess of production for the same period in 2009. Favorable drilling results have been the primary contributors to production growth in these areas. Natural gas production volumes increased 2,337 MMcf, or 11%, during the year ended December 31, 2010 compared to the same period in 2009. Natural gas production in the Bakken field in the North region was up 2,172 MMcf compared to the same period in 2009 due to additional natural gas being connected and sold in North Dakota. Natural gas production in the Oklahoma Woodford area increased 1,471 MMcf due to additional wells being completed and producing during the year ended December 31, 2010 compared to 2009. The increased natural gas production in the Bakken and Oklahoma Woodford plays was partially offset by decreases in natural gas volumes of 916 MMcf in the Cedar Hills field due to the conversion of producing wells to injection wells and 801 MMcf due to natural declines in non-Woodford areas in the South region.

Revenues

Crude Oil and Natural Gas Sales. Crude oil and natural gas sales for the year ended December 31, 2010 were $948.5 million, a 55% increase from sales of $610.7 million for 2009. Our realized price per Boe increased $14.60 to $59.70 for the year ended December 31, 2010 from $45.10 for the year ended December 31, 2009. Our sales volumes increased 2,348 MBoe, or 17%, over the same period in 2009 due to the continuing success of our drilling programs in the Bakken field and additional natural gas being connected and sold in the North region. The differential between NYMEX calendar month average crude oil prices and our realized crude oil price per barrel for the year ended December 31, 2010 was $9.02 compared to $8.29 for 2009. 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 and demand fluctuations.

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Derivatives. We are required to recognize all derivative instruments on the balance sheet as either assets or liabilities measured at fair value. We have not designated our derivative instruments as hedges for accounting purposes. 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 consolidated income statements under the caption Loss on mark-to-market derivative instruments, net.

During the year ended December 31, 2010, we realized gains on natural gas derivatives of $22.3 million and realized gains on crude oil derivatives of $13.2 million. During the year ended December 31, 2010, we reported an unrealized non-cash mark-to-market gain on natural gas derivatives of $19.8 million and an unrealized non-cash mark-to-market loss on crude oil derivatives of $186.0 million. During the year ended December 31, 2009, we realized gains on natural gas derivatives of $0.6 million and reported an unrealized non-cash mark-to-market gain on natural gas derivatives of $1.6 million and an unrealized non-cash mark-to-market loss on crude oil derivatives of $3.7 million.

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. The table below shows the volumes and prices for the sale of reclaimed crude oil for the periods presented.

	Year ended December 31,		
Reclaimed crude oil sales	**2010**	**2009**	**Variance**
Average sales price ($/Bbl)	$ 69.35	$ 48.57	$ 20.78
Sales volumes (barrels)	227,000	199,000	28,000

During the year ended December 31, 2010, prices for reclaimed crude oil sold from our central treating units were $20.78 per barrel higher than the comparable 2009 period, which contributed to an increase in reclaimed crude oil revenue of $5.8 million to $16.8 million, contributing to an overall increase in crude oil and natural gas service operations revenue of $4.3 million for the year ended December 31, 2010. During the year ended December 31, 2009, we sold high-pressure air from our Red River units to a third party and recorded revenues of $2.2 million. Beginning January 2010, we no longer sell high-pressure air to a third party. Associated crude oil and natural gas service operations expenses increased $7.3 million to $18.1 million during the year ended December 31, 2010 compared to the same period in 2009 due mainly to an increase in the costs of purchasing and treating reclaimed crude oil for resale.

Operating Costs and Expenses

Production Expenses, Production Taxes and Other Expenses. Production expense remained consistent at $93.2 million during the years ended December 31, 2010 and 2009. Production expense per Boe decreased to $5.87 for the year ended December 31, 2010 from $6.89 per Boe for the year ended December 31, 2009. In the prior year, we leased compressors from a related party for approximately $400,000 per month under an operating lease and a new agreement was negotiated effective February 1, 2010 through November 2010 resulting in the monthly lease fee being reduced to $50,000, lowering production expense per Boe for the 2010 period. The per unit decrease was also driven by longer natural production periods on certain North Dakota Bakken wells that resulted in lower artificial lifting costs, positive secondary recovery efforts in the Cedar Hills field that have resulted in lower-cost improvements in production, and the conversion of certain high pressure air injection units to less costly waterflood units during 2010, which also contributed to lower-cost improvements in production. We plan to convert some waterflood units to high pressure air injection units on certain fields in 2011, which may result in increased production expenses compared to 2010.

Production taxes and other expenses increased $31.0 million, or 68%, during the year ended December 31, 2010 compared to the year ended December 31, 2009 as a result of higher revenues resulting from increased commodity prices and sales volumes along with the expiration of various tax incentives. Production taxes and other expenses on the consolidated income statements include charges for marketing, gathering, dehydration and compression fees primarily related to natural gas sales in the Arkoma Woodford area of $6.1 million and $6.8 million for the years ended December 31, 2010 and 2009, respectively. Production taxes, excluding other expenses, as a percentage of crude oil and natural gas sales were 7.5% for the year ended December 31, 2010 compared to 6.5% for the year ended December 31, 2009. The increase is due to the expiration of various tax incentives coupled with higher taxable revenues in North Dakota, our most active area, which has production tax rates of up to 11.5% of crude oil revenues. 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 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 production tax rate is expected to increase as production tax incentives we currently receive for horizontal wells reach the end of their incentive periods.

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

$/Boe	Year Ended December 31, 2010	2009	Percent increase (decrease)
Production expenses	$ 5.87	$ 6.89	(15%)
Production taxes and other expenses	4.82	3.37	43%
Production expenses, production taxes and other expenses	$ 10.69	$ 10.26	4%

Exploration Expenses. Exploration expenses consists primarily of dry hole costs and exploratory geological and geophysical costs that are expensed as incurred. Exploration expenses increased $0.1 million in the year ended December 31, 2010 to $12.8 million due primarily to an increase in seismic expense of $3.8 million to $5.8 million offset by a decrease in dry hole expense of $3.5 million to $3.0 million. The majority of the dry hole costs, 76%, were in the South region for the year ended December 31, 2010 and 67% of the dry hole costs for the 2009 period were in the East region.

Depreciation, Depletion, Amortization and Accretion (DD&A). Total DD&A increased $36.0 million, or 17%, in the year ended December 31, 2010 compared to the same period in 2009, primarily due to an increase in production volumes. The following table shows the components of our DD&A rate per Boe.

$/Boe	Year Ended December 31, 2010	2009
Crude oil and natural gas	$ 14.92	$ 14.94
Other equipment	0.24	0.23
Asset retirement obligation accretion	0.17	0.17
Depreciation, depletion, amortization and accretion	$ 15.33	$ 15.34

Property Impairments. Property impairments, both proved and non-producing, decreased in the year ended December 31, 2010 by $18.7 million to $65.0 million compared to $83.7 million during the year ended December 31, 2009.

Impairment of non-producing properties increased $16.2 million during the year ended December 31, 2010 to $63.3 million compared to $47.1 million for 2009 reflecting higher amortization of leasehold costs resulting from a larger base of amortizable costs. 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 proved crude oil and natural gas properties were approximately $1.7 million for the year ended December 31, 2010 compared to approximately $36.6 million for the year ended December 31, 2009, a decrease of $34.9 million, or 95%. We evaluate our proved 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 value based on discounted cash flows. Impairments of proved properties in 2010 reflect uneconomic operating results in the East region and a non-Bakken field in the North region. Impairments of proved properties in 2009 were primarily related to uneconomic wells in our South region and a non-Bakken field in the North region.

General and Administrative Expenses. General and administrative expenses increased $8.0 million to $49.1 million during the year ended December 31, 2010 from $41.1 million during the comparable period of 2009. General and administrative expenses include non-cash charges for stock-based compensation of $11.7 million and $11.4 million for the years ended December 31, 2010 and 2009, respectively. General and administrative expenses, excluding equity compensation, increased $7.7 million for the year ended December 31, 2010 compared to the year ended December 31, 2009. The increase was primarily related to an increase in personnel costs and office related expenses associated with the growth of our Company during the year. On a volumetric basis, general and administrative expenses increased $0.06 to $3.09 per Boe for the year ended December 31, 2010 compared to $3.03 per Boe for the year ended December 31, 2009.

Interest Expense. Interest expense increased $29.9 million, or 129%, for the year ended December 31, 2010 compared to the year ended December 31, 2009 due to an increase in our outstanding debt balance and higher rates of interest on our senior notes in the current year as compared to lower interest rates on our credit facility borrowings in the prior year. On September 23, 2009, we issued $300 million of 8 1/4% Senior Notes due 2019. On April 5, 2010, we issued $200 million of 7 3/8% Senior Notes due 2020. On September 16, 2010, we issued $400 million of 7 1/8% Senior Notes due 2021. We recorded $45.4 million in interest expense on the outstanding senior notes for the year ended December 31, 2010. Including the interest on the senior notes, our weighted average interest rate for the year ended December 31, 2010 was 6.98% with a weighted average outstanding long-term debt balance of $685.8 million compared to a weighted average interest rate of 3.78% and a weighted average outstanding long-term debt balance of $507.7 million for the year ended December 31, 2009.

Our weighted average outstanding revolving credit facility balance decreased to $121.7 million for the year ended December 31, 2010 compared to $426.3 million for the year ended December 31, 2009. The weighted average interest rate on our revolving credit facility borrowings was lower at 2.73% for the year ended December 31, 2010 compared to 2.90% for the same period in 2009. At December 31, 2010, we had $30.0 million of outstanding borrowings on our revolving credit facility.

Income Taxes. Income taxes for the year ended December 31, 2010 were $90.2 million compared to $38.7 million for the year ended December 31, 2009. We provided for income taxes at a combined federal and state tax rate of approximately 35% for both 2010 and 2009 after taking into account permanent taxable differences. See *Notes to Consolidated Financial Statements Note 8. Income Taxes* for more information. In January 2011, new tax legislation was enacted in the State of Illinois that substantially increases the state income tax rates for individuals and corporations in that state. A significant portion of our East region properties are located in the Illinois Basin; thus, our financial condition and results of operations will be negatively impacted by the tax rate changes in Illinois. Although we are still analyzing the effects of the legislation, we estimate that the tax rate change will increase our consolidated full-year 2011 effective tax rate by approximately 0.1% and result in an increase in our 2011 income tax expense. We will record the impact of the changes beginning in our income tax provision for the quarter ending March 31, 2011.

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 were 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.

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Derivatives. We are required to recognize all derivative instruments on the balance sheet as either assets or liabilities measured at fair value. We have not designated our derivative instruments as hedges for accounting pruposes. 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, net.

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.

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 Expenses, Production Taxes and Other Expenses. Production expenses 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 expenses 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 expenses 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 taxes 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 taxes and other expenses on the consolidated income statements include 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 taxes, excluding other expenses, as a percentage of crude oil and natural gas sales were 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. For 2009, 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 expenses and production taxes and other expenses were as follows:

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

Exploration Expenses. Exploration expenses consist primarily of dry hole costs and exploratory geological and geophysical costs that are expensed as incurred. Exploration expenses 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.

Depreciation, Depletion, Amortization and Accretion. 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.

$/Boe	Year Ended December 31, 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, both proved and non-producing, 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 proved 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 proved 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 of proved properties 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 of proved properties in 2008 were primarily related to uneconomic wells in our South region and our Rockies Other area in the North region.

General and Administrative Expenses. General and administrative expenses 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 expenses include 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 expenses 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 expenses were $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 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 (the 2019 Notes). The 2019 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 2019 Notes for the year ended December 31, 2009. Including the effect of the 2019 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.

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 senior notes. During the year ended December 31, 2010, our average realized crude oil sales price was $16.25 per barrel higher, or 30%, than the year ended December 31, 2009, and we saw our realized natural gas sales prices increase $1.27 per Mcf, or 39%, in 2010 compared to the same period in 2009. The increased prices of crude oil and natural gas in 2010 as well as increased sales volumes resulted in improved cash flows from operations. Further, our liquidity has improved at December 31, 2010 as we have more borrowing availability on our revolving credit facility as a result of refinancing our credit facility borrowings via the issuance of senior notes in 2010.

At December 31, 2010, we had approximately $7.9 million of cash and cash equivalents and approximately $717.6 million of net available liquidity under our revolving credit facility (after considering outstanding letters of credit).

Cash Flows

Cash Flows from Operating Activities

Our net cash flows provided by operating activities were $653.2 million, $373.0 million and $719.9 million for the years ended December 31, 2010, 2009 and 2008, respectively. The increase in operating cash flows in 2010 compared to 2009 was primarily due to higher revenues as a result of higher commodity prices and sales volumes in the current period. The decrease in operating cash flows in 2009 compared to 2008 was primarily due to a decrease in revenues in 2009 as a result of lower commodity prices.

Cash Flows from Investing Activities

During the years ended December 31, 2010, 2009 and 2008, we had cash flows used in investing activities (excluding asset sales) of $1,083.4 million, $507.0 million and $930.8 million, respectively, related to our capital program, inclusive of dry hole costs. The increase in our cash flows used in investing activities in 2010 compared to 2009 was due to the acceleration of our drilling program, primarily in the Bakken shale of North Dakota and the Anadarko Woodford shale in Oklahoma, which resulted in increased capital expenditures in 2010. The decrease in our cash flows used in investing activities in 2009 compared to 2008 was primarily due to decreases in capital expenditures as a result of lower commodity prices in 2009.

Cash Flows from Financing Activities

During the years ended December 31, 2010, 2009 and 2008, we had cash flows provided by financing activities of $379.9 million, $135.8 million and $204.2 million, respectively. Net cash provided by financing activities of $379.9 million for 2010 was primarily the result of proceeds received upon the issuance of $200 million of 7 3/8% Senior Notes due 2020 (the 2020 Notes) in April 2010 and the issuance of $400 million of 7 1/8% Senior Notes due 2021 (the 2021 Notes) in September 2010 along with borrowings on our credit facility, partially offset by amounts repaid under our credit facility. Net cash provided by financing activities of $135.8 million for 2009 was primarily the result of proceeds received from the issuance of $300 million of 8 1/4% Senior Notes due 2019 (the 2019 Notes) in September 2009 along with borrowings on our credit facility, partially offset by amounts repaid under our credit facility. Net cash provided by financing activities of $204.2 million for 2008 was primarily the result of borrowings under our revolving credit facility, partially offset by amounts repaid under our credit facility.

Future Sources of Financing

We believe that funds from operating cash flows and our 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.

Based on our planned production growth and the existence of derivative contracts in place to limit the downside risk of adverse price movements associated with the forecasted sale of future production, we currently anticipate that we will be able to generate or obtain funds sufficient to meet our short-term and 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, but may also include the issuance of debt or equity securities or the sale of assets. Furthermore, the issuance of debt requires 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.

Revolving Credit Facility

On June 30, 2010, we entered into an amended and restated revolving credit agreement. The amended and restated credit agreement amended and restated our previous credit agreement to, among other things:

Increase the maximum size of the revolving credit facility from $750 million to $2.5 billion;

Maintain aggregate commitments under the revolving credit facility of $750 million, which may be increased at our option from time to time (provided there exists no default) up to the lesser of $2.5 billion or the borrowing base then in effect;

Increase the borrowing base from the previous $1.0 billion to an initial amount of $1.3 billion, subject to semi-annual redetermination;

Modify the applicable margin for Eurodollar and reference rate advances. Eurodollar margins range from 1.75% to 2.75% and reference rate margins range from 0.75% to 1.75%, based on the amount of total outstanding borrowings in relation to the borrowing base; and

Extend the maturity of the revolving credit facility from April 12, 2011 to July 1, 2015.

Our amended credit facility is backed by a syndicate of 14 banks. We believe that each member of the current syndicate of banks has the capability to fund its commitment. If one or more lenders cannot fund its commitment, we would not have the full availability of the $750 million commitment.

The most recent borrowing base redetermination was completed in December 2010, whereby the lenders approved an increase in our borrowing base from $1.3 billion to $1.5 billion. We have elected to maintain the aggregate commitment level at $750 million. In the future, we may not be able to access adequate funding under our credit facility 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. We expect the next borrowing base redetermination to occur in the second quarter of 2011. 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.

We had $30.0 million of outstanding borrowings under our credit facility at December 31, 2010 and $226.0 million outstanding at December 31, 2009. As of December 31, 2010, we had $717.6 million of borrowing availability under our credit facility (after considering outstanding letters of credit). On September 16, 2010, we issued $400 million of the 2021 Notes and received net proceeds of approximately $393.0 million after deducting initial purchasers fees. The net proceeds were used to repay all borrowings then outstanding under our credit facility, which had a balance prior to payoff of $182 million. Subsequent to the September 16, 2010 payoff, no additional borrowings were made under the credit facility until December 2010. The $30.0 million of outstanding borrowings at December 31, 2010 were borrowed on December 29, 2010. As of February 18, 2011, we have $95.0 million of outstanding borrowings and $652.6 million of borrowing availability under our revolving credit facility.

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. Our credit agreement also contains requirements that we maintain a current ratio of not less than 1.0 to 1.0 and a ratio of total funded debt to EBITDAX of no greater than 3.75 to 1.0. As defined by our credit agreement, the current ratio represents our ratio of current assets to current liabilities, inclusive of available borrowing capacity under the credit agreement and exclusive of current balances associated with derivative contracts and asset retirement obligations. EBITDAX represents earnings before interest expense, income taxes, depreciation, depletion, amortization and accretion, property impairments, exploration expenses, unrealized derivative gains and losses and non-cash equity 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 7. Management s Discussion and Analysis of Financial Condition and Results of Operations Non-GAAP Financial Measures*. The total funded debt to EBITDAX ratio represents the sum of outstanding borrowings and letters of credit under our revolving credit facility plus our senior note obligations, divided by total EBITDAX for the most recent four quarters. We were in compliance with these covenants at December 31, 2010 and we expect to maintain compliance for at least the next 12 months. At December 31, 2010, our current ratio was approximately 2.1 to 1.0 and our total funded debt to EBITDAX ratio was approximately 1.1 to 1.0. We do not believe the restrictive covenants will limit, or are reasonably likely to limit, our ability to undertake additional debt or equity financing to a material extent.

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.

Issuances of Long-Term Debt

On September 23, 2009, we issued the 2019 Notes and received net proceeds of approximately $289.7 million after deducting the initial purchasers discounts and fees. On April 5, 2010, we issued the 2020 Notes and received net proceeds of approximately $194.2 million after deducting the initial purchasers discounts and fees. The net proceeds from these offerings were used to repay a portion of the borrowings then outstanding under our revolving credit facility that were incurred to fund capital expenditures. On September 16, 2010, we issued the 2021 Notes and received net proceeds of approximately $393.0 million after deducting initial purchasers fees. The net proceeds were used to repay all borrowings then outstanding under the revolving credit facility that were incurred to fund capital expenditures and to increase cash balances to fund a portion of our accelerated capital program.

The 2019 Notes, 2020 Notes, and 2021 Notes (together, the Notes) will mature on October 1, 2019, October 1, 2020, and April 1, 2021, respectively. Interest on the Notes is payable semi-annually on April 1 and October 1 of each year, with interest on the 2021 Notes commencing on April 1, 2011. We have the option to redeem all or a portion of the 2019 Notes, 2020 Notes, and 2021 Notes at any time on or after October 1, 2014, October 1, 2015, and April 1, 2016, respectively, at the redemption prices specified in the Notes respective indentures (together, the Indentures) plus accrued and unpaid interest. We may also redeem the Notes, in whole or in part, at the make-whole redemption prices specified in the Indentures, plus accrued and unpaid interest, at any time prior to October 1, 2014, October 1, 2015, and April 1, 2016 for the 2019 Notes, 2020 Notes, and 2021 Notes, respectively. In addition, we may redeem up to 35% of the 2019 Notes, 2020 Notes, and 2021 Notes prior to October 1, 2012, October 1, 2013, and April 1, 2014, respectively, under certain circumstances with the net cash proceeds from certain equity offerings. Currently, we have no plans or intentions of exercising an early redemption option on the Notes. The Notes are not subject to any mandatory redemption or sinking fund requirements.

The Indentures contain certain restrictions on our ability to incur additional debt, pay dividends on our common stock, make certain investments, create certain liens on assets, engage in certain transactions with affiliates, transfer or sell certain assets, consolidate or merge, or sell substantially all of our assets. These covenants are subject to a number of important exceptions and qualifications. We were in compliance with these covenants as of December 31, 2010 and expect to maintain compliance for at least the next 12 months. We do not believe the restrictive covenants will limit, or are reasonably likely to limit, our ability to undertake additional debt or equity financing to a material extent. Our subsidiary, which currently has no independent assets or operations, fully and unconditionally guarantees the Notes.

Registration Statement Filing

On July 16, 2010, we filed a shelf registration statement on Form S-3 pursuant to which we may offer from time to time one or more series of debt and equity securities. We may issue additional long-term debt and equity securities from time to time when market conditions are favorable and when the need arises. The nature, amounts, terms, and timing of such financing arrangements, and the related impact on our financial position, results of operations, and liquidity are currently indeterminable. The issuance of additional equity securities could have a dilutive effect on the value of our common stock.

Future Capital Requirements

Capital Expenditures

We evaluate opportunities to purchase or sell crude oil and natural gas properties 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.

During the year ended December 31, 2010, we participated in the completion of 349 gross (122.6 net) wells and invested a total of $1,237.2 million (including increases in accruals for capital expenditures of $148.0 million and $5.8 million of seismic costs) in our capital program as shown in the following table.

In millions	**Amount**
Exploration and development drilling	$ 803.0
Land costs	343.1
Capital facilities, workovers and re-completions	30.5
Vehicles, computers and other equipment	44.5
Acquisition of producing properties	7.3
Seismic	5.8
Dry holes	3.0
Total	$ 1,237.2

Our 2010 capital expenditures primarily focused on increased development in the Bakken shale of North Dakota and the Anadarko Woodford shale in western Oklahoma.

In October 2010, our Board of Directors approved a 2011 capital expenditures budget of $1.36 billion. Our 2011 planned capital expenditures are expected to be allocated as follows:

In millions	**Amount**
Exploration and development drilling	$ 1,135
Land costs	108
Capital facilities, workovers and re-completions	92
Seismic	15
Vehicles, computers and other equipment	6
Total	$ 1,356

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The 2011 capital expenditures budget of $1.36 billion will continue to focus primarily on increased development in the Bakken shale of North Dakota and the Anadarko Woodford shale in western Oklahoma.

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 available borrowing capacity under our revolving credit facility will be sufficient to fund our 2011 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.

Contractual Obligations

We have the following contractual obligations and commitments as of December 31, 2010:

	Payments due by period				
In thousands	**Total**	**Less than 1 year (2011)**	**1 - 3 years (2012-2013)**	**3 - 5 years (2014-2015)**	**More than 5 years**
Arising from arrangements on the balance sheet:					
Revolving credit facility	$ 30,000	$	$	$ 30,000	$
Senior Notes[1]	900,000				900,000
Interest expense[2]	658,400	69,200	138,590	137,798	312,812
Asset retirement obligations[3]	56,320	2,241	10,714	1,854	41,511
Arising from arrangements not on the balance sheet:					
Operating leases[4]	633	204	270	148	11
Drilling rig commitments[5]	80,851	74,338	6,513		
Fracturing and well stimulation commitments[6]	53,625	19,500	34,125		
Total contractual obligations	$ 1,779,829	$ 165,483	$ 190,212	$ 169,800	$ 1,254,334

(1) Amounts represent scheduled maturities of our debt obligations at December 31, 2010 and do not reflect the discounts at which the Notes were issued. See *Notes to Consolidated Financial Statements Note 7. Long-Term Debt* for a description of our senior notes.

(2) Interest expense includes scheduled cash interest payments on the senior notes as well as estimated interest payments on our revolving credit facility borrowings outstanding at December 31, 2010 and assumes that the interest rate on our credit facility borrowings of 4.00% at December 31, 2010 continues for the life of the revolving credit facility.

(3) Amounts represent estimated discounted costs for future dismantlement and abandonment of our crude oil and natural gas properties.

(4) Operating lease obligations represent operating leases for office space and office equipment. See *Notes to Consolidated Financial Statements Note 9. Lease Commitments.*

(5) We have various drilling rig contracts with various terms extending through June 2012. These contracts were entered into in the normal course of business to ensure rig availability to allow us to execute our business objectives in our key strategic plays. These drilling commitments are not recorded in the accompanying consolidated balance sheets.

(6) On August 20, 2010, we entered into an agreement with a third party whereby the third party will provide, on a take-or-pay basis, hydraulic fracturing services and related equipment to service certain of our properties in North Dakota and Montana. The arrangement has a term of three years, beginning in September 2010, with two one-year extensions available to us at our discretion. Pursuant to the take-or-pay arrangement, we will pay a fixed rate per day for a minimum number of days per calendar quarter over the three-year term regardless of whether or not the services are provided. Fixed commitments amount to $4.9 million per quarter, or $19.5 million annually, for total future commitments of $58.5 million over the three-year term. Future commitments remaining as of December 31, 2010 amount to $53.6 million. The commitments under this arrangement are not recorded in the accompanying consolidated balance sheets.

In 2010, we signed a throughput and deficiency agreement with a third party crude oil pipeline company committing to ship 10,000 barrels of crude oil per day for five years at a tariff of $1.85 per barrel. The third party system is scheduled to commence operations late in the second quarter of 2011. We will use this system to move some of our North region crude oil to market.

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Crude Oil and Natural Gas Hedging

As part of our risk management program, we hedge a portion of our anticipated future crude oil and natural gas production to achieve more predictable cash flows and 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 program. 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. 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. Currently, all of our derivative contracts are with parties that are lenders (or affiliates of lenders) under our revolving credit agreement. Substantially all of our hedging transactions are settled based upon reported settlement prices on the NYMEX.

Please see *Notes to Consolidated Financial Statements Note 5. Derivative Contracts* for further discussion of the accounting applicable to our derivative instruments, a listing of open contracts as of December 31, 2010 and the estimated fair value of those contracts as of that date.

Between January 1, 2011 and February 18, 2011, 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			
		Swaps	Floors		Ceilings	
Period and Type of Contract	**Bbls**	**Weighted Average**	**Range**	**Weighted Average**	**Range**	**Weighted Average**
January 2012 December 2012						
Swaps	915,000	$ 100.01				
January 2013 December 2013						
Collars	3,102,500		$ 90-$95	$ 91.59	$ 97.25-$101.60	$ 99.13

Natural Gas

Period and Type of Contract	**MMBtus**	**Swaps Weighted Average**
January 2011 March 2011		
Swaps	2,360,000	$ 4.69
April 2011 June 2011		
Swaps	3,640,000	4.69
July 2011 September 2011		
Swaps	3,910,000	4.69
October 2011 December 2011		
Swaps	4,232,000	4.73
January 2012 December 2012		
Swaps	3,660,000	5.07

Critical Accounting Policies and Estimates

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 our management to 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 be 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, impairment of assets and income taxes. Management s judgments and estimates in these areas are based on information available from both internal and external sources, including engineers, geologists and historical experience in similar matters. Actual results could differ from the estimates as additional information becomes known.

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

Our external independent reserve engineers and internal technical staff prepare the estimates of our crude oil and natural gas reserves and associated future net cash flows. 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 economically producible in future periods from known reservoirs under existing economic and operating conditions. Even though our external independent reserve engineers and internal 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.

There has been only limited interpretive guidance regarding reporting of reserve estimates under the new SEC rules implemented in 2009 and there may not be further interpretive guidance on the new rules. Accordingly, while the estimates of our proved reserves at December 31, 2010 included in this report have been prepared based on what we and our independent reserve engineers believe to be reasonable interpretations of the 2009 rules, those estimates could differ materially from any estimates we might prepare in the future by applying more specific interpretive guidance should that guidance become available.

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 and are reflected in our financial statements as crude oil and natural gas sales. These variances have historically not been material.

Derivative Activities

We 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. 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 of our price risk management activities 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 in current earnings. As such, 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 sheets.

In determining the amounts to be recorded for our open derivative contracts, we are required to estimate the fair value of the derivatives. We use an independent third party to provide our derivative valuations. The third party s 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 collar contracts requires the use of an option-pricing model. The estimated future prices are compared to the prices fixed by the derivative agreements and the resulting estimated future cash inflows or outflows over the lives of the derivatives 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 incurred to acquire mineral interests in crude oil and natural gas properties, to drill and equip exploratory wells that find proved reserves, to drill and equip development wells 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 of capitalized drilling and development costs of crude oil and natural gas properties, including related support equipment and facilities, 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 leaseholds 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 reserves are established based on estimates made by our internal geologists and engineers and external independent reserve 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 depreciation, depletion and amortization are eliminated from the accounts and the resulting gain or loss, if any, is recognized.

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 are 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 crude oil and natural gas properties, which consist primarily of undeveloped leasehold costs and costs associated with the purchase of proved undeveloped reserves, are assessed for impairment on a property-by-property basis for individually significant balances, if any, and on an aggregate basis by prospect 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. For individually insignificant non-producing properties, the amount of the impairment loss recognized is determined by amortizing the portion of the unproved properties costs which management estimates will not be transferred to proved properties over the life of the lease based on experience of successful drilling and the average holding period. The estimated rate of successful drilling is highly judgmental and is 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 deferred 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, 2010, we believe that all of our deferred tax assets recorded on our consolidated balance sheets will ultimately be utilized. 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 could increase in the period it is determined that it is more likely than not that a deferred tax asset will not be utilized.

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. 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 with unconsolidated entities to enhance liquidity and capital resources. However, as is customary in the crude oil and natural gas industry, we have various contractual commitments that are not reflected in the consolidated balance sheets as shown under *Item 7. Management s Discussion and Analysis of Financial Condition and Results of Operations Contractual Obligations.*

Recent Accounting Pronouncements Not Yet Adopted

For a description of the accounting standards that we adopted in 2010, see *Notes to Consolidated Financial Statements Note 1. Organization and Summary of Significant Accounting Policies*.

Various accounting standards and interpretations were issued in 2010 with effective dates subsequent to December 31, 2010. We have evaluated the recently issued accounting pronouncements that are effective in 2011 and believe that none of them will have a material effect on our financial position, results of operations or cash flows when adopted.

Further, we are closely monitoring the joint standard-setting efforts of the Financial Accounting Standards Board and the International Accounting Standards Board. There are a large number of pending accounting standards that are being targeted for completion in 2011 and beyond, including, but not limited to, standards relating to revenue recognition, accounting for leases, fair value measurements, accounting for financial instruments, disclosure of loss contingencies and financial statement presentation. Because these pending standards have not yet been finalized, at this time we are not able to determine the potential future impact that these standards will have, if any, on our financial position, results of operations or cash flows.

Pending Legislative and Regulatory Initiatives

The crude oil and natural gas industry in the United States is subject to various types of regulation at the federal, state and local levels. Laws, rules and regulations affecting the crude oil and natural gas industry have been pervasive and are under continual review for amendment or expansion. The following are significant laws and regulations that have been enacted or are currently being considered by regulatory bodies that may affect us in the areas in which we operate.

Dodd-Frank Wall Street Reform and Consumer Protection Act. On July 21, 2010, President Obama signed into law the Dodd-Frank Act, which, among other things, establishes federal oversight and regulation of the over-the-counter derivatives market and the entities, such as us, that participate in that market. The new legislation, to the extent applicable to us or our derivative counterparties, may result in increased costs and cash collateral requirements for the types of derivative instruments we use to hedge and otherwise manage our financial and commercial risks related to fluctuations in commodity prices, and could have an adverse effect on our ability to hedge risks associated with our business. Further, the Dodd-Frank Act requires the SEC to develop a rule that would require certain issuers to disclose the payments they make to the US Federal Government or foreign governments related to the commercial development of crude oil and natural gas. The final rules related to derivatives reform and government payments are expected to be issued in 2011. Many of the key concepts and processes under the Dodd-Frank Act are not yet finalized and must be delineated by rules and regulations which have been and are being adopted by the applicable regulatory agencies. As a consequence, it is not possible at this time to predict the effects that the Dodd-Frank Act or the resulting rules and regulations may have on our hedging activities or our consolidated financial statements.

Climate change. Federal, state and local laws and regulations are increasingly being enacted to address concerns about the effects that carbon dioxide emissions and other identified greenhouse gases may have on the environment and climate worldwide. These effects are widely referred to as climate change. On December 15, 2009, the EPA 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 the warming of the earth s atmosphere and other climatic changes. These findings by the EPA have allowed the agency to implement recent regulations that restrict emissions of greenhouse gases, beginning in 2011 in some instances. As a crude oil and natural gas company, the debate on climate change is relevant to our operations because the equipment we use to explore for, develop and produce crude oil and natural gas emits greenhouse gases. Additionally, the combustion of carbon-based fuels, such as the crude oil and natural gas that we sell, emits carbon dioxide and other greenhouse gases. Thus, any one of the federal, state or local climate change initiatives could have a material adverse effect on our business. The climate change laws and regulations could adversely affect demand for the crude oil and natural gas that we produce by stimulating demand for alternative forms of energy that do not rely on the combustion of fossil fuels. Although our compliance with any regulation of greenhouse gases may result in increased compliance and operating costs, we do not expect the costs to comply with the currently applicable regulations to be material. It is not possible at this time to estimate the costs or operational impacts we could experience to comply with new legislative or regulatory developments. We do not anticipate that we would be impacted by the climate change initiatives to any greater degree than other similar competitors.

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Hydraulic fracturing. The U.S. Congress is currently considering legislation to amend the federal Safe Drinking Water Act to remove the exemption for hydraulic fracturing operations and require reporting and disclosure of chemicals used by the crude oil and natural gas industry in the hydraulic fracturing process, including, for example, the Fracturing Responsibility and Awareness of Chemicals Act of 2009. Sponsors of bills pending before the U.S. Congress have asserted that chemicals used in the fracturing process could adversely affect drinking water supplies. These bills, if adopted, could increase the possibility of litigation and establish an additional level of regulation at the federal or state level that could prohibit hydraulic fracturing or could lead to operational delays or increased operating costs and could result in additional regulatory burdens, making it more difficult to perform hydraulic fracturing and increasing our costs of compliance. These legislative and regulatory initiatives, to the extent they are adopted or continue, could prohibit or limit our ability to develop our crude oil and natural gas properties located in unconventional formations, which could adversely affect our ability to access, develop, and book reserves in the future. Compliance, or the consequences of any failure to comply by us, could have a material adverse effect on our financial condition and results of operations. However, at this time it is not possible to estimate the potential impact on our business that may arise if federal or state legislation is enacted into law.

Health Care Reform Acts. In March 2010, President Obama signed into law the Patient Protection and Affordable Care Act and the Health Care and Education Reconciliation Act of 2010 (collectively, the 2010 Acts). The 2010 Acts expand health care coverage to many uninsured individuals and expand coverage to those already insured, among other things. The 2010 Acts will impact employers and businesses differently depending on the size of the organization and the specific impacts on a company s employees. The 2010 Acts could require, among other things, changes to our current employee benefit plans, our administrative and accounting processes, or our information technology infrastructure, any of which could cause us to incur additional health care and other costs. The provisions of the 2010 Acts are not expected to have a significant impact on our financial statements in the short term. The ultimate longer term extent and potential costs of the changes are currently uncertain at this time and are being evaluated as regulations and interpretations of the 2010 Acts become available.

Recently Enacted Tax Legislation

On December 17, 2010, President Obama signed into law the Tax Relief, Unemployment Insurance Reauthorization and Job Creation Act of 2010 (the Act), which, among other things, provides income tax relief for businesses by extending tax benefits and credits that either previously expired or were scheduled to expire in 2010. Most notably for the Company, the Act extends and enhances the bonus depreciation provisions of the Internal Revenue Code for two years. Specifically, the Act allows for a 100% first-year depreciation deduction for qualified property that is acquired after September 8, 2010 and placed in service prior to January 1, 2012. Further, with respect to qualified property placed in service during 2012, the Act allows for a 50% first-year depreciation deduction. These changes will have a positive impact on our capital-intensive business by reducing Federal income taxes currently payable. At December 31, 2010, in the period of enactment, we have recorded an income tax benefit associated with the applicable tax law changes outlined in the Act, which resulted in a $23.1 million decrease in Federal taxable income.

On January 13, 2011, the Governor of the State of Illinois signed State Senate Bill 2505 (SB 2505), which substantially increases the state income tax rates for individuals and corporations in Illinois. A significant portion of our East region properties are located in the Illinois Basin; thus, our financial condition and results of operations will be adversely impacted by the tax rate changes in Illinois. SB 2505 increases the current corporate income tax rate from 4.8% to 7.0% for tax years 2011 to 2014. For tax years 2015 to 2024, the tax rate decreases to 5.25% and then decreases again to 4.8% for tax years beginning on or after January 1, 2025. SB 2505 also imposes a personal property tax replacement tax of 2.5% in addition to the base corporate income tax rate, making the combined corporate income tax rate 9.5% for tax years 2011 to 2014, 7.75% for tax years 2015 to 2024, and 7.3% for tax years 2025 and beyond. Further, SB 2505 temporarily suspends the use of net operating loss carryovers for tax years ending after December 31, 2010 and prior to December 31, 2014 and makes changes to the estimated tax payment requirements. SB 2505 was enacted subsequent to December 31, 2010 and, therefore, no resulting incremental income tax expense is reflected in our effective tax rate for 2010 as a result of the tax rate changes. Although we are still analyzing the effects of SB 2505, we estimate that the tax rate change will increase our consolidated full-year 2011 effective tax rate by approximately 0.1% and result in an increase in our 2011 income tax expense. We will record the impact of the changes beginning in our income tax provision for the quarter ending March 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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Non-GAAP Financial Measures

EBITDAX

We present EBITDAX throughout this Annual Report on Form 10-K, which is a non-GAAP financial measure. EBITDAX represents earnings before interest expense, income taxes, depreciation, depletion, amortization and accretion, property impairments, exploration expenses, unrealized derivative gains and losses, and non-cash equity compensation expense. EBITDAX is not a measure of net income or cash flows as determined by GAAP. Management believes EBITDAX is useful because it allows them to more effectively evaluate our operating performance and compare the results of our operations from period to period without regard to our financing methods or capital structure. We exclude the items listed above from net income in arriving at EBITDAX because those amounts can vary substantially from company to company within our industry depending upon accounting methods and book values of assets, capital structures and the method by which the assets were acquired. 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 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 1.0 on a rolling four-quarter basis. This ratio represents the sum of outstanding borrowings and letters of credit under our revolving credit facility plus our senior note obligations, divided by total EBITDAX for the most recent four quarters. We were in compliance with this covenant at December 31, 2010. At that date, our total funded debt to EBITDAX ratio was approximately 1.1 to 1.0. A violation of this covenant in the future could result in a default under our revolving credit facility. In the event of such default, the lenders under our revolving credit facility could elect to terminate their commitments thereunder, cease making further loans, and could declare all outstanding amounts, together with accrued interest, to be due and payable. If the indebtedness under our revolving credit facility were to be accelerated, our assets may not be sufficient to repay in full such indebtedness. Our revolving credit facility defines EBITDAX consistently with the definition of EBITDAX utilized and presented by us. The following table provides a reconciliation of our net income to EBITDAX for the periods presented.

	Year ended December 31,				
	2010	2009	2008	2007	2006
			(in thousands)		
Net income	$ 168,255	$ 71,338	$ 320,950	$ 28,580	$ 253,088
Interest expense	53,147	23,232	12,188	12,939	11,310
Provision (benefit) for income taxes	90,212	38,670	197,580	268,197	(132)
Depreciation, depletion, amortization and accretion	243,601	207,602	148,902	93,632	65,428
Property impairments	64,951	83,694	28,847	17,879	11,751
Exploration expenses	12,763	12,615	40,160	9,163	19,738
Unrealized losses on derivatives	166,257	2,089		26,703	
Non-cash equity compensation	11,691	11,408	9,081	12,792	10,932
EBITDAX	$ 810,877	$ 450,648	$ 757,708	$ 469,885	$ 372,115

PV-10

Our PV-10 value, a non-GAAP financial measure, is derived from the Standardized Measure of discounted future net cash flows, which is the most directly comparable financial measure computed using GAAP. PV-10 generally differs from Standardized Measure because it does not include the effects of income taxes on future net revenues. At December 31, 2010, our PV-10 totaled approximately $4.6 billion. The Standardized Measure of our discounted future net cash flows was approximately $3.8 billion at December 31, 2010, representing a $0.8 billion difference from PV-10 because of the tax effect. We believe that the presentation of PV-10 is relevant and useful to investors because it presents the discounted future net cash flows attributable to proved reserves held by companies without regard to the specific tax characteristics of such entities and is a useful measure of evaluating the relative monetary significance of our crude oil and natural gas properties. Investors may utilize PV-10 as a basis for comparing the relative size and value of our proved reserves to other companies. PV-10 should not be considered as a substitute for, or more meaningful than, the Standardized Measure as determined in accordance with GAAP. Neither PV-10 nor Standardized Measure represents an estimate of the fair market value of our crude oil and natural gas properties.

Item 7A. Quantitative and Qualitative Disclosures About Market Risk

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

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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, 2010 and excluding any effect of our derivative instruments in place, our annual revenue would increase or decrease by approximately $118.2 million for each $10.00 per barrel change in crude oil prices and $23.9 million for each $1.00 per Mcf 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 as part of our risk management program. In addition, we may utilize basis contracts to hedge the differential between NYMEX 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 program. 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.

For the year ended December 31, 2010, we realized gains on natural gas derivatives of $22.3 million and realized gains on crude oil derivatives of $13.2 million. For the year ended December 31, 2010, we reported an unrealized non-cash mark-to-market gain on natural gas derivatives of $19.8 million and an unrealized non-cash mark-to-market loss on crude oil derivatives of $186.0 million. The fair value of our derivative instruments at December 31, 2010 was a net liability of $168.3 million. An assumed increase in the forward commodity prices used in the year-end valuation of our derivative instruments of $10.00 per Bbl for crude oil and $1.00 per MMBtu for natural gas would increase our net derivative liability to $488.0 million at December 31, 2010. Conversely, an assumed decrease in forward commodity prices of $10.00 per Bbl for crude oil and $1.00 per MMBtu for natural gas would change our derivative valuation to a net asset of $130.0 million at December 31, 2010.

For a further discussion of our hedging activities, see information at *Item 7. Management s Discussion and Analysis of Financial Condition and Results of Operations Crude Oil and Natural 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.

On July 21, 2010, President Obama signed into law the Dodd-Frank Act, which, among other things, establishes federal oversight and regulation of the over-the-counter derivatives market and the entities that participate in that market. Significant regulations are required to be promulgated by the SEC and the Commodity Futures Trading Commission within 360 days from the date of enactment to implement the new legislation. The new legislation, to the extent applicable to the Company or its derivatives counterparties, may result in increased costs and cash collateral requirements for the types of derivative instruments the Company uses to hedge and otherwise manage its financial and commercial risks related to fluctuations in commodity prices, and could have an adverse effect on the Company s ability to hedge risks associated with its business. Many of the key concepts and processes under the Dodd-Frank Act are not defined and must be delineated by rules and regulations which have been and are being adopted by the applicable regulatory agencies. As a consequence, it is not possible at this time to predict the effects that the Dodd-Frank Act or the resulting rules and regulations may have on the Company s hedging activities.

Credit Risk. We monitor our risk of loss due to non-performance by counterparties of their contractual obligations. Our principal exposure to credit risk is through the sale of our crude oil and natural gas production, which we market to energy marketing companies, refineries and affiliates ($213.3 million in receivables at December 31, 2010), our joint interest receivables ($269.5 million at December 31, 2010), and counterparty credit risk associated with our derivative instrument receivables ($21.4 million at December 31, 2010).

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. Historically, our credit losses on crude oil and natural gas sales receivables have been immaterial.

Joint interest receivables arise from billing entities who own a 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 often 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. This liability was $47.7 million as of December 31, 2010, which will be used to offset future capital costs when billed. 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 order to secure payment or, if necessary, foreclose on the interest. Historically, our credit losses on joint interest receivables have been immaterial.

Our use of derivative instruments involves the risk that our counterparties will be unable to meet their commitments under the arrangements. We manage this risk by using multiple counterparties who we consider to be financially strong in order to minimize our exposure to credit risk with any individual counterparty. Currently, all of our derivative contracts are with parties that are lenders (or affiliates of lenders) under our revolving credit agreement.

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Interest Rate Risk. Our exposure to changes in interest rates relates primarily to variable-rate borrowings outstanding under our revolving credit facility. We manage our interest rate exposure by monitoring both the effects of market changes in interest rates and the proportion of our debt portfolio that is variable-rate versus fixed-rate debt. 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 may be used solely to modify interest rate exposure and not to modify the overall leverage of the debt portfolio. We currently have no interest rate derivatives. We had $95.0 million of outstanding borrowings under our revolving credit facility at February 18, 2011. The impact of a 1% increase in interest rates on this amount of debt would result in increased interest expense of approximately $1.0 million per year and a $0.6 million decrease in net income per year. Our revolving credit facility matures on July 1, 2015 and the weighted-average interest rate at February 18, 2011 was 2.36%.

The following table presents our long-term debt maturities and the weighted average interest rates by expected maturity date as of December 31, 2010:

In millions	2011	2012	2013	2014	2015	Thereafter	Total
Fixed rate debt:							
Notes:							
Principal amount [1]	$	$	$	$	$	$ 900.0	$ 900.0
Weighted-average interest rate						7.56%	7.56%
Variable rate debt:							
Revolving credit facility:							
Principal amount	$	$	$	$	$ 30.0	$	$ 30.0
Weighted-average interest rate					4.00%		4.00%

(1) This amount does not reflect the discounts at which the Notes were issued.

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 Notes.

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Item 8. Financial Statements and Supplementary Data

Index to Consolidated Financial Statements

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, 2010 and 2009, and the related consolidated statements of income, shareholders equity and cash flows for each of the three years in the period ended December 31, 2010. 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, 2010 and 2009, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2010 in conformity with accounting principles generally accepted in the United States of America.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), Continental Resources, Inc. and Subsidiary s internal control over financial reporting as of December 31, 2010, 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 25, 2011 expressed an unqualified opinion.

/s/ GRANT THORNTON LLP

Oklahoma City, Oklahoma

February 25, 2011

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Continental Resources, Inc. and Subsidiary

Consolidated Balance Sheets

	December 31, 2010	December 31, 2009
	In thousands, except par values and share data	
Assets		
Current assets:		
Cash and cash equivalents	$ 7,916	$ 14,222
Receivables:		
Crude oil and natural gas sales	208,211	119,565
Affiliated parties	20,156	7,823
Joint interest and other, net	254,471	55,970
Derivative assets	21,365	2,218
Inventories	38,362	26,711
Deferred and prepaid taxes	22,672	4,575
Prepaid expenses and other	9,173	4,944
Total current assets	582,326	236,028
Net property and equipment, based on successful efforts method of accounting	2,981,991	2,068,055
Debt issuance costs, net	27,468	10,844
Total assets	$ 3,591,785	$ 2,314,927
Liabilities and shareholders equity		
Current liabilities:		
Accounts payable trade	$ 390,892	$ 91,248
Revenues and royalties payable	133,051	66,789
Payables to affiliated parties	4,438	9,612
Accrued liabilities and other	94,829	45,294
Derivative liabilities	76,771	4,307
Current portion of asset retirement obligations	2,241	2,460
Total current liabilities	702,222	219,710
Long-term debt	925,991	523,524
Other noncurrent liabilities:		
Deferred income tax liabilities	582,841	489,241
Asset retirement obligations, net of current portion	54,079	47,707
Noncurrent derivative liabilities	112,940	
Other noncurrent liabilities	5,557	4,466
Total other noncurrent liabilities	755,417	541,414
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; 170,408,652 shares issued and outstanding at December 31, 2010; 169,968,471 shares issued and outstanding at December 31, 2009	1,704	1,700
Additional paid-in-capital	439,900	430,283
Retained earnings	766,551	598,296
Total shareholders equity	1,208,155	1,030,279

Total liabilities and shareholders equity	$ 3,591,785	$ 2,314,927

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,		
	2010	**2009**	**2008**
	In thousands, except per share data		
Revenues:			
Crude oil and natural gas sales	$ 917,503	$ 584,089	$ 875,213
Crude oil and natural gas sales to affiliates	31,021	26,609	64,693
Loss on mark-to-market derivative instruments, net	(130,762)	(1,520)	(7,966)
Crude oil and natural gas service operations	21,303	17,033	28,550
Total revenues	839,065	626,211	960,490
Operating costs and expenses:			
Production expenses	86,557	76,719	80,935
Production expenses to affiliates	6,646	16,523	20,700
Production taxes and other expenses	76,659	45,645	58,610
Exploration expenses	12,763	12,615	40,160
Crude oil and natural gas service operations	18,065	10,740	18,188
Depreciation, depletion, amortization and accretion	243,601	207,602	148,902
Property impairments	64,951	83,694	28,847
General and administrative expenses	49,090	41,094	35,719
Gain on sale of assets	(29,588)	(709)	(894)
Total operating costs and expenses	528,744	493,923	431,167
Income from operations	310,321	132,288	529,323
Other income (expense):			
Interest expense	(53,147)	(23,232)	(12,188)
Other	1,293	952	1,395
	(51,854)	(22,280)	(10,793)
Income before income taxes	258,467	110,008	518,530
Provision for income taxes	90,212	38,670	197,580
Net income	$ 168,255	$ 71,338	$ 320,950
Basic net income per share	$ 1.00	$ 0.42	$ 1.91
Diluted net income per share	$ 0.99	$ 0.42	$ 1.89

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	Total shareholders equity
		In thousands, except share data			
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
Excess tax benefit on stock-based compensation			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
Net income				168,255	168,255
Excess tax benefit on stock-based compensation			5,230		5,230
Stock-based compensation			11,691		11,691
Stock options:					
Exercised	207,220	2	255		257
Repurchased and canceled	(59,877)	(1)	(2,661)		(2,662)
Restricted stock:					
Issued	449,114	4			4
Repurchased and canceled	(100,561)	(1)	(4,898)		(4,899)
Forfeited	(55,715)				
Balance, December 31, 2010	170,408,652	$ 1,704	$ 439,900	$ 766,551	$ 1,208,155

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,		
	2010	**2009**	**2008**
		In thousands	
Cash flows from operating activities:			
Net income	$ 168,255	$ 71,338	$ 320,950
Adjustments to reconcile net income to net cash provided by operating activities:			
Depreciation, depletion, amortization and accretion	242,748	208,885	148,573
Property impairments	64,951	83,694	28,847
Change in fair value of derivatives	166,257	2,089	(26,703)
Stock-based compensation	11,691	11,408	9,081
Provision for deferred income taxes	77,359	36,119	184,115
Excess tax benefit from stock-based compensation	(5,230)	(2,872)	
Dry hole costs	3,024	6,477	20,002
Gain on sale of assets	(29,588)	(709)	(894)
Other, net	4,366	2,607	780
Changes in assets and liabilities:			
Accounts receivable	(299,480)	48,738	(65,989)
Inventories	(11,651)	(4,501)	(3,834)
Prepaid expenses and other	(2,398)	21,961	(16,520)
Accounts payable trade	146,473	(117,643)	101,967
Revenues and royalties payable	66,262	(11,371)	10,811
Accrued liabilities and other	47,842	13,842	8,545
Other noncurrent liabilities	2,286	2,924	184
Net cash provided by operating activities	653,167	372,986	719,915
Cash flows from investing activities:			
Exploration and development	(1,031,499)	(497,496)	(841,479)
Purchase of crude oil and natural gas properties	(7,338)	(1,217)	(74,662)
Purchase of other property and equipment	(44,564)	(8,257)	(14,651)
Proceeds from sale of assets	43,985	7,148	3,175
Net cash used in investing activities	(1,039,416)	(499,822)	(927,617)
Cash flows from financing activities:			
Revolving credit facility borrowings	341,000	426,100	443,000
Repayment of revolving credit facility	(537,000)	(576,500)	(231,600)
Proceeds from issuance of Senior Notes	587,210	297,480	
Other debt		3,304	
Repayment of other debt		(3,304)	
Debt issuance costs	(9,191)	(10,028)	(1,717)
Repurchase of equity grants	(7,561)	(4,299)	(6,748)
Excess tax benefit from stock-based compensation	5,230	2,872	
Dividends to shareholders	(2)	(41)	(207)
Exercise of stock options	257	245	1,442
Net cash provided by financing activities	379,943	135,829	204,170
Net change in cash and cash equivalents	(6,306)	8,993	(3,532)
Cash and cash equivalents at beginning of period	14,222	5,229	8,761
Cash and cash equivalents at end of period	$ 7,916	$ 14,222	$ 5,229

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. The Company was originally formed in 1967 to explore for, develop and produce crude oil and natural gas properties. Continental s operations are in the North, South and East regions of the United States. The North region consists of properties north of Kansas and west of the Mississippi river and includes North Dakota Bakken, Montana Bakken, the Red River units and the Niobrara shale play in Colorado and Wyoming. The South region includes Kansas and all properties south of Kansas and west of the Mississippi river including the Arkoma and Anadarko Woodford plays in Oklahoma. The East region contains properties east of the Mississippi river including the Illinois Basin and the state of Michigan. As of December 31, 2010, approximately 70% of the Company s estimated proved reserves were located in the North region. As of December 31, 2010, the Company had interests in 2,726 wells and serves as the operator of 1,888, or 69%, of those wells.

Basis of presentation

Continental has one wholly owned subsidiary, Banner Pipeline Company, L.L.C., 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 (U.S. GAAP) 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 most significant of the estimates and assumptions that affect reported results is the estimate of the Company s crude oil and natural gas reserves, which is used to compute depreciation, depletion, amortization and impairment of producing crude oil and natural gas properties. In the opinion of management, all adjustments (consisting only of normal recurring adjustments) necessary for a fair presentation in accordance with U.S. GAAP have been included in these consolidated financial statements.

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 the Company estimates the volumes sold and the price at which they were sold to record revenue. The following table shows the amounts of estimated crude oil and natural gas sales recorded as of December 31 for each indicated year.

		December 31,	
	2010	**2009**	**2008**
		In thousands	
Estimated crude oil and natural gas sales	$ 263,075	$ 129,082	$ 86,350

Variances between estimated revenue and actual amounts received are recorded in the month payment is received and are recorded in the financial statements in the caption Revenues Crude Oil and Natural Gas Sales . These variances have historically not been material. 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 percen