CONTINENTAL RESOURCES INC
Form 10-K
February 24, 2012

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, 2011

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

Indicate by check mark if the 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.

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 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, 2011 was approximately $3.7 billion, based upon the closing price of $64.91 per share as reported by the New York Stock Exchange on such date.

180,863,580 shares of our $0.01 par value common stock were outstanding on February 15, 2012.

DOCUMENTS INCORPORATED BY REFERENCE

Portions of the definitive Proxy Statement of Continental Resources, Inc. for the Annual Meeting of Stockholders to be held in 2012, 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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When we refer to us, we, our, Company, or Continental we are describing Continental Resources, Inc. and/or our subsidiaries.

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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, which represents the amount of energy needed to heat one pound of water by one degree Fahrenheit and can be used to describe the energy content of fuels.

completion The process of treating a drilled well followed by the installation of permanent equipment for the production of crude oil and/or natural gas.

conventional play An area 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.

de-risked Refers to acreage and locations in which the Company believes the geological risks and uncertainties related to recovery of crude oil and natural gas have been reduced as a result of drilling operations to date. However, only a portion of such acreage and locations have been assigned proved undeveloped reserves and ultimate recovery of hydrocarbons from such acreage and locations remains subject to all risks of recovery applicable to other acreage.

developed acreage The number of acres 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 gas Refers to natural gas that remains in a gaseous state in the reservoir and does not produce large quantities of liquid hydrocarbons when brought to the surface. Also may refer to gas that has been processed or treated to remove all natural gas liquids.

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 which allows for drilling multiple 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 sometimes 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.

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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.

hydraulic fracturing A process involving the high pressure injection of water, sand and additives into rock formations to stimulate crude oil and natural gas production.

in-field well A well drilled between producing wells in a field to provide more efficient recovery of crude oil or natural gas from the reservoir.

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.

MMBo One million barrels of crude oil.

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

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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 renewal is reasonably certain.

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

proved undeveloped reserves or *PUD* Proved reserves 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.

resource play Refers to an expansive contiguous geographical area with prospective crude oil and/or natural gas reserves that has the potential to be developed uniformly with repeatable commercial success due to advancements in horizontal drilling and multi-stage fracturing technologies.

royalty interest Refers to the ownership of a percentage of the resources or revenues produced from a crude oil or natural gas property. A royalty interest owner does not bear 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 2009 and later) 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 the 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.

unconventional play An area 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 oil and 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 *Part I, 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;
- our future operations;

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our reserves;

our technology;

our financial strategy;

crude oil and natural gas prices;

the 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;

marketing of crude oil and natural gas;

transportation of crude oil and natural gas to markets;

exploitation or property acquisitions;

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

our financial position;

general economic conditions;

credit markets;

our liquidity and access to capital;

- the impact of regulatory and legal proceedings involving us and of scheduled or potential regulatory changes;
- our future operating results; and
- plans, objectives, expectations and intentions contained in this report that are not historical, including, without limitation, statements regarding our future growth plans.

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 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 *Part I, Item 1A. Risk Factors* in this report, quarterly reports and 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 Part I, 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 subsidiaries.

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. 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 Anadarko Woodford and Arkoma Woodford plays in Oklahoma. The East region contains properties east of the Mississippi river including the Illinois Basin and the state of Michigan.

We were originally formed in 1967 to explore for, develop and produce crude oil and natural gas properties. Through 1989, our activities and growth remained focused primarily in Oklahoma. In 1989, we expanded our activity into the North region. Approximately 71% of our estimated proved reserves as of December 31, 2011 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 allow 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 439.0 MMBoe of proved crude oil and natural gas reserves through extensions and discoveries from January 1, 2007 through December 31, 2011 compared to 4.8 MMBoe added through proved reserve acquisitions during that same period.

As of December 31, 2011, our estimated proved reserves were 508.4 MMBoe, with estimated proved developed reserves of 205.2 MMBoe, or 40% of our total estimated proved reserves. Crude oil comprised 64% of our total estimated proved reserves as of December 31, 2011. For the year ended December 31, 2011, we generated crude oil and natural gas revenues of $1.65 billion and operating cash flows of $1.1 billion. For the year ended December 31, 2011, daily production averaged 61,865 Boe per day, a 43% increase over average production of 43,318 Boe per day for the year ended December 31, 2010. Average daily production for the quarter ended December 31, 2011 increased 57% to 75,219 Boe per day from 48,034 Boe per day for the quarter ended December 31, 2010.

The following table summarizes our total estimated proved reserves, PV-10 and net producing wells as of December 31, 2011, average daily production for the quarter ended December 31, 2011 and the reserve-to-production index in our principal regions. Our reserve estimates as of December 31, 2011 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 96% of our PV-10, 97% of our proved crude oil reserves, and 81% of our proved natural gas reserves as of December 31, 2011. 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, 2011 were determined using the 12-month unweighted arithmetic average of the first-day-of-the-month commodity prices for the period of January 2011

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through December 2011, without giving effect to derivative transactions, and were held constant throughout the lives of the properties. These prices were $96.19 per Bbl for crude oil and $4.12 per MMBtu for natural gas ($88.71 per Bbl for crude oil and $5.59 per Mcf for natural gas adjusted for location and quality differentials).

	At December 31, 2011				Average daily production for fourth quarter 2011 (Boe per day)		
	Proved reserves (MBoe)	Percent of total	PV-10 (1) (In millions)	Net producing wells		Percent of total	Annualized reserve/production index (2)
North Region:							
Bakken field							
North Dakota Bakken	255,977	50.4%	$ 4,996.3	292	35,565	47.3%	19.7
Montana Bakken	38,217	7.5%	848.8	138	5,678	7.5%	18.4
Red River units							
Cedar Hills	48,147	9.5%	1,654.5	132	11,784	15.7%	11.2
Other Red River units	15,909	3.1%	362.0	112	3,462	4.6%	12.6
Other	4,213	0.8%	71.6	211	964	1.3%	12.0
South Region:							
Oklahoma Woodford							
Anadarko Woodford	93,637	18.4%	833.6	56	9,820	13.0%	26.1
Arkoma Woodford	38,977	7.7%	172.9	57	3,688	4.9%	29.0
Other	9,223	1.8%	134.8	297	3,080	4.1%	8.2
East Region	4,138	0.8%	125.8	530	1,178	1.6%	9.6
Total	508,438	100.0%	$ 9,200.3	1,825	75,219	100.0%	18.5

(1) PV-10 is a non-GAAP financial measure and generally differs from Standardized Measure, the most directly comparable GAAP financial measure, because it does not include the effects of income taxes on future net revenues. The Standardized Measure at December 31, 2011 is $7.5 billion, a $1.7 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 2011 production into estimated proved reserve volumes at December 31, 2011.

The following table provides additional information regarding our key development areas as of December 31, 2011 and the budgeted amounts we plan to spend on exploratory and development drilling, capital workovers, and facilities in 2012.

	Developed acres		Undeveloped acres		Gross wells planned for drilling	2012 Plan Capital expenditures (1) (in millions)
	Gross	Net	Gross	Net		
North Region:						
Bakken field						
North Dakota Bakken	498,317	236,052	814,740	427,185	470	$ 989
Montana Bakken	97,367	75,802	250,423	176,824	18	94
Red River units	150,534	131,428			12	44
Niobrara						
Colorado/Wyoming	1,283	1,013	198,780	114,495	26	59

Other	61,348	45,624	231,124	129,383	5		9
South Region:							
Oklahoma Woodford							
Anadarko Woodford	98,150	56,634	346,195	221,482	159		377
Arkoma Woodford	105,967	24,892	26,931	14,702	1		2
Southern Woodford	670	130	39,400	14,322			
Other	100,515	47,435	44,471	18,974	25		44
East Region	48,832	46,307	137,202	112,058	43		11
Total	1,162,983	665,317	2,089,266	1,229,425	759	$	1,629

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(1) Capital expenditures budgeted for 2012 include amounts for drilling, capital workovers and facilities and exclude budgeted amounts for land of $94 million, seismic of $20 million, and $7 million for vehicles, computers and other equipment. Potential acquisition expenditures are not budgeted. We expect our cash flows from operations, our remaining cash balance, and the availability under our revolving credit facility will be sufficient to meet our capital expenditure needs for the next 12 months. 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 1980s we began to believe the valuation potential for crude oil exceeded that of natural gas. Accordingly, we began to shift our reserve and production profiles toward crude oil. As of December 31, 2011, crude oil comprises 64% of our total proved reserves and 73% of our 2011 annual production. Although we do pursue liquids-rich natural gas opportunities, such as the Anadarko Woodford play in Oklahoma, we continue to believe crude oil valuations will be superior to natural gas valuations on a relative Btu basis for the foreseeable future.

Growth Through Drilling. A substantial portion of our annual capital expenditures are invested in drilling projects and acreage acquisitions. From January 1, 2007 through December 31, 2011, proved crude oil and natural gas reserve additions through extensions and discoveries were 439.0 MMBoe compared to 4.8 MMBoe of proved reserve acquisitions.

Internally Generated Prospects. Although we periodically evaluate and complete strategic acquisitions, our technical staff has internally generated a substantial portion 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, Three Forks and Oklahoma Woodford formations. Production rates in the Red River units also have been increased through the use of enhanced recovery technologies including water and high pressure air injection. Our production from the Red River units, the Bakken field, and the Oklahoma Woodford play comprised approximately 20,635 MBoe, or 91%, of our total crude oil and natural gas production for the year ended December 31, 2011.

Acquire Significant Acreage Positions in New or Developing Plays. In addition to the 969,010 net undeveloped acres held in the Bakken play in North Dakota and Montana, the Oklahoma Woodford play, and the Niobrara play in Colorado and Wyoming, we held 260,415 net undeveloped acres in other crude oil and natural gas plays as of December 31, 2011. 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 we believe will help us successfully execute our business strategy:

Large Acreage Inventory. We own 1,229,425 net undeveloped acres and 665,317 net developed acres as of December 31, 2011. Approximately 79% of the net undeveloped acres are located within unconventional resource plays in the Bakken (North Dakota and Montana), Woodford (Oklahoma) and the Niobrara (Colorado and Wyoming). The remaining balance of the net undeveloped acreage is located in conventional plays including 3D-defined locations for the Trenton-Black River (Michigan), Lodgepole (North Dakota), Morrow-Springer (Western Oklahoma) and Frio (South Texas).

Horizontal Drilling and Enhanced Recovery Experience. In 1992, we drilled our first horizontal well, and we have drilled over 1,100 horizontal wells since that time. We also have substantial experience with enhanced recovery methods and currently serve as the operator of 49 waterflood units. Additionally, we operate 6 high pressure air injection floods.

Control Operations Over a Substantial Portion of Our Assets and Investments. As of December 31, 2011, we operated properties comprising 86% 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 31 years of crude oil and natural gas industry experience. Additionally, our technical staff, which includes 48 petroleum engineers, 26 geoscientists and 26 landmen, has an average of 15 years experience in the industry.

Strong Financial Position. We have a revolving credit facility with lender commitments totaling $1.25 billion and a borrowing base of $2.25 billion as of February 15, 2012, with available borrowing capacity of $347.2 million at that date after considering outstanding borrowings and letters of credit. While our current commitments total $1.25 billion, we have the ability to increase the aggregate commitment level up to the lesser of $2.5 billion or the borrowing base then in effect to provide additional available liquidity if needed to maintain our growth strategy, take advantage of business opportunities, and fund our capital program. We believe our planned exploration and development activities will be funded substantially from our operating cash flows and borrowings under our revolving credit facility. Our 2012 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 differ from expectations, we believe our credit facility will have sufficient availability to fund any deficit or that we can reduce our capital expenditures to be in line with cash flows from operations.

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. These rules 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 require 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.

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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 17. 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 prior to the time at which contracts providing the right to operate expire, unless evidence indicates renewal is reasonably certain. 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 PV-10 by reserve category as of December 31, 2011. The total Standardized Measure of discounted cash flows as of December 31, 2011 is also presented. Ryder Scott evaluated properties representing approximately 96% of our PV-10, 97% of our proved crude oil reserves, and 81% of our proved natural gas reserves as of December 31, 2011, and our internal 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, 2011 were determined using the 12-month unweighted arithmetic average of the first-day-of-the-month commodity prices for the period of January 2011 through December 2011, without giving effect to derivative transactions, and were held constant throughout the lives of the properties. These prices were $96.19 per Bbl for crude oil and $4.12 per MMBtu for natural gas ($88.71 per Bbl for crude oil and $5.59 per Mcf for natural gas adjusted for location and quality differentials).

	Crude Oil (MBbls)	Natural Gas (MMcf)	Total (MBoe)	PV-10 (1) (in millions)
Proved developed producing	144,468	361,265	204,679	$ 5,617.1
Proved developed non-producing	556		556	3.6
Proved undeveloped	181,109	732,567	303,203	3,579.6
Total proved reserves	326,133	1,093,832	508,438	$ 9,200.3
Standardized Measure				$ 7,505.4

(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, 2011 is $7.5 billion, a $1.7 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, 2011.

	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	62,822	93,023	78,325	146,418	187,401	177,652
Montana Bakken	16,480	18,450	19,555	15,651	18,064	18,662
Red River units						
Cedar Hills	42,253	17,611	45,189	2,958		2,958
Other Red River units	12,210	347	12,267	3,642		3,642
Other	2,917	6,758	4,043	20	900	170
South Region:						
Oklahoma Woodford						
Anadarko Woodford	2,585	103,830	19,890	11,950	370,786	73,747
Arkoma Woodford	110	77,032	12,949	203	154,950	26,028
Other	1,901	42,838	9,042	104	466	181
East Region	3,746	1,376	3,975	163		163
Total	145,024	361,265	205,235	181,109	732,567	303,203

We have historically added reserves through our exploration program and development activities as discussed in *Part I, Item 1. Business Crude Oil and Natural Gas Operations*. Reserves at December 31, 2009, 2010 and 2011 were computed using the 12-month unweighted average of the first-day-of-the-month commodity prices as required by 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	2011	2010	2009
Proved reserves at beginning of year	364,712	257,293	159,262
Revisions of previous estimates	2,237	27,629	1,195
Extensions, discoveries and other additions	161,981	95,233	110,454
Production	(22,581)	(15,811)	(13,623)
Sales of minerals in place			
Purchases of minerals in place	2,089	368	5
Proved reserves at end of year	508,438	364,712	257,293

Revisions. Revisions represent changes in previous reserve 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 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. Extensions, discoveries and other additions for the year ended December 31, 2011 were primarily due to increases in proved reserves associated with our successful drilling activity in the Bakken field in North Dakota and Anadarko Woodford play in Oklahoma.

We expect a significant portion of future reserve additions will come from our major development projects in the Bakken and Anadarko Woodford plays. We also expect to participate as a buyer of properties when and if we have the ability to increase our position in strategic plays at favorable terms.

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, 96% of our PV-10, 97% of our proved crude oil reserves, and 81% of our proved natural gas reserves as of December 31, 2011 included in this Annual Report on Form 10-K. The Ryder Scott technical personnel 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. Refer to Exhibit 99 included with this Annual Report on Form 10-K for further discussion of the qualifications of Ryder Scott personnel.

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, certain members of our senior management review and approve the Ryder Scott reserve report and on a quarterly basis any internally estimated significant changes to our proved reserves.

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 26 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, 2011 were 303,203 MBoe, consisting of 181,109 MBbls of crude oil and 732,567 MMcf of natural gas. In 2011, we developed approximately 13% of our proved undeveloped reserves booked as of December 31, 2010 through the drilling of 141 gross (68.2 net) development wells at an aggregate capital cost of approximately $448 million. Also in 2011, we removed 230 gross (49.9 net) PUD locations. This resulted in the removal of 1.7 MMBo and 135.4 Bcf of proved undeveloped reserves (24.2 MMBoe). These removals were predominantly due to our decision to declassify 0.2 MMBo and 130.4 Bcf (21.9 MMBoe) of proved undeveloped reserves in our Arkoma Woodford district, which consists primarily of dry gas. These reserves were originally scheduled to be developed by year-end 2013. However, given current and projected prices for natural gas, we elected to defer drilling and as a result declassified these proved undeveloped reserves accordingly. Estimated future development costs relating to the development of proved undeveloped reserves are projected to be approximately $1.5 billion in 2012, $1.6 billion in 2013, $1.4 billion in 2014, $0.5 billion in 2015 and $0.2 billion in 2016.

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

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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) 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 increase our 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 the majority of our currently 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, 2011:

	Developed Acres		Undeveloped Acres		Total	
	Gross	Net	Gross	Net	Gross	Net
North Region:						
Bakken field						
North Dakota Bakken	498,317	236,052	814,740	427,185	1,313,057	663,237
Montana Bakken	97,367	75,802	250,423	176,824	347,790	252,626
Red River units	150,534	131,428			150,534	131,428
Niobrara						
Colorado/Wyoming	1,283	1,013	198,780	114,495	200,063	115,508
Other	61,348	45,624	231,124	129,383	292,472	175,007
South Region:						
Oklahoma Woodford						
Anadarko Woodford	98,150	56,634	346,195	221,482	444,345	278,116
Arkoma Woodford	105,967	24,892	26,931	14,702	132,898	39,594
Southern Woodford	670	130	39,400	14,322	40,070	14,452
Other	100,515	47,435	44,471	18,974	144,986	66,409
East Region	48,832	46,307	137,202	112,058	186,034	158,365
Total	1,162,983	665,317	2,089,266	1,229,425	3,252,249	1,894,742

The following table sets forth the number of gross and net undeveloped acres as of December 31, 2011 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:

	2012		2013		2014	
	Gross	Net	Gross	Net	Gross	Net
North Region:						
Bakken field						
North Dakota Bakken	171,591	82,009	308,952	145,590	159,951	86,453
Montana Bakken	18,870	17,605	93,131	54,824	86,546	67,196
Red River units						
Niobrara						
Colorado/Wyoming	1,200	969	52,165	32,380	14,778	9,408
Other	42,921	21,419	52,117	38,812	5,580	3,480
South Region:						
Oklahoma Woodford						
Anadarko Woodford	50,995	29,721	156,018	100,829	102,086	63,923
Arkoma Woodford	12,199	6,696	7,330	5,118	240	173
Southern Woodford	5,915	3,015	11,840	4,317	19,666	6,489
Other	3,729	2,060	6,070	4,210	7,160	2,575
East Region	63,313	56,351	41,018	32,424	7,709	5,699
Total	370,733	219,845	728,641	418,504	403,716	245,396

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Drilling Activity

During the three years ended December 31, 2011, we drilled exploratory and development wells as set forth in the table below:

	2011		2010		2009	
	Gross	Net	Gross	Net	Gross	Net
Exploratory wells:						
Crude oil	50	23.4	42	11.8	14	6.5
Natural gas	109	45.9	25	10.9	34	9.0
Dry holes	2	1.3	4	2.2	16	9.0
Total exploratory wells	161	70.6	71	24.9	64	24.5
Development wells:						
Crude oil	380	126.1	231	91.5	106	39.1
Natural gas	17	1.6	44	5.2	45	4.1
Dry holes	5	0.6	3	1.0	2	0.1
Total development wells	402	128.3	278	97.7	153	43.3
Total wells	563	198.9	349	122.6	217	67.8

As of December 31, 2011, there were 195 gross (62.2 net) wells in the process of drilling, completing or waiting on completion.

As of February 15, 2012, we operated 36 rigs on our properties. Our rig activity during 2012 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 *Part I, 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 2012. Although we cannot provide any assurance, we believe our cash flows from operations, remaining cash balance, and borrowing availability under our revolving credit facility will be sufficient to satisfy our 2012 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 commodity 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 believed to be capable of producing crude oil and natural gas occurring in discrete accumulations in structural and stratigraphic traps. Unconventional plays are areas 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 oil and gas shale, tight oil and gas sands and coalbed methane. Our operations in unconventional plays include operations in the Bakken and Woodford plays 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 hydraulic fracturing 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 86% of our PV-10 as of December 31, 2011. During the three months ended December 31, 2011, our average daily production from such properties was 50,529 net Bbls of crude oil and 41,545 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 is 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. In October 2011, the USGS began a study to update their 2008 assessment of recoverable reserves for the Bakken field to reflect the increased recoveries due to new geologic models applied to the Bakken Formation, advances in drilling and production technologies, and additional crude oil discoveries in the field. Results of the USGS study are expected to be announced in 2013.

Drilling activity and production rates in the Bakken field continued to increase in 2011, reaching record levels in North Dakota, according to a report issued by the NDIC on January 17, 2012. As of February 6, 2012, there were 210 rigs drilling in the Bakken field, up 21% from the 174 rigs that were drilling as of February 18, 2011. 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 1,660,847 gross (915,863 net) acres as of December 31, 2011. We are also the most active driller in the Bakken field, with 22 operated rigs drilling as of February 15, 2012. During 2011 we completed 390 gross (122.3 net) wells in the Bakken field. Our properties within the Bakken field represented 64% of our PV-10 as of December 31, 2011 and 55% of our average daily Boe production for the three months ended December 31, 2011. As of December 31, 2011 we had completed 1,042 gross (382.9 net) wells in the Bakken field. Our inventory of proved undeveloped drilling locations in the Bakken field as of December 31, 2011 totaled 1,131 gross (497.4 net) wells.

During 2011, we saw our production, reserves and acreage position in the Bakken field grow 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 43,148 net Boe per day during the month of December 2011, up 69% from our average daily Bakken field production in December 2010. Total proved Bakken field reserves at December 31, 2011 were 294 MMBoe, up 49% over our proved Bakken field reserves as of December 31, 2010. Our net acreage position in the Bakken field increased 7% during 2011, from 855,936 net acres as of December 31 2010 to 915,863 net acres as of December 31, 2011. Approximately 34% of our net acreage is developed and 66% of our net acreage is undeveloped as of December 31, 2011.

We plan to invest approximately $1,040.7 million drilling 488 gross (126.2 net) wells in the Bakken field during 2012. Approximately 91% will be invested in North Dakota and the remaining 9% will be invested in Montana. We plan to average 24 rigs drilling in the Bakken field throughout the year, with 21 rigs located in North Dakota and 3 rigs in Montana.

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North Dakota Bakken. Our production and reserve growth in the Bakken field during 2011 came primarily from our activities in North Dakota. Production increased to an average rate of 37,177 net Boe per day during the month of December 2011, up 78% from the average daily rate in December 2010. Proved reserves grew 62% year-over-year to 256 MMBoe as of December 31, 2011. Our estimated average ultimate recoverable reserves per well (1,280-acre spacing) also increased during the year from 518 MBoe gross to 603 MBoe gross based on historical well performance. As of December 31, 2011, our North Dakota Bakken properties represented 54% of our PV-10 and 47% of our average daily Boe production for the three months ended December 31, 2011. We completed 369 gross (109.5 net) wells during 2011, bringing our total number of wells drilled in the North Dakota Bakken to 849 gross (260.8 net) as of December 31, 2011. As of December 31, 2011, we had 1,313,057 gross (663,237 net) acres in the North Dakota Bakken field, of which 36% of the net acreage is developed and 64% of the net acreage is undeveloped. Our inventory of proved net undeveloped locations stood at 1,050 gross (442.4 net) wells as of December 31, 2011.

One of the more significant outcomes of our 2011 drilling activity in the North Dakota Bakken was the discovery of three additional layers or benches of oil bearing rock in the Three Forks formation based on six drilling cores taken at various locations across the North Dakota Bakken field. This discovery redefined the Bakken petroleum system and prompted the NDIC to expand the definition of the Bakken reservoir, in certain areas of the field, to include all zones from 50 feet above the top of the Bakken Formation down to the base of the Three Forks Formation. These three benches are found approximately 50 to 150 feet below the traditional Middle Bakken and Upper (first bench) Three Forks reservoir and indicate that more oil exists under our leasehold than previously perceived. This, in turn, could translate into increased recoverable reserves from our acreage. To prove these three benches add reserves will require additional drilling. In October 2011, we successfully drilled and completed our first well in the second bench of the Three Forks formation. The Charlotte 2-22H was completed flowing 1,396 Boe per day from the second bench of the Three Forks and is producing in line with a typical commercial first bench Three Forks producing well.

Another significant achievement during 2011 was the successful expansion of the play west of the Nesson anticline. During the year we drilled 80 gross (49.3 net) wells west of the anticline and as of February 15, 2012 had 10 rigs drilling in this area. We also continued to expand the use of our ECO-Pad™ technology during the year. ECO-Pad technology allows 4 wells (2 in the Bakken Formation and 2 in the Three Forks Formation) 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 reduced by utilizing a walking rig, which moves between wells on hydraulic feet that eliminate the need to break down the rig each time it moves from one well to another well. Completion costs are reduced 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%. As of December 31, 2011, we had completed 12 ECO-Pad locations and had 4 ECO-Pad rigs drilling or completing wells. 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 the year, our access to natural gas pipeline infrastructure also improved significantly. At this time, the majority of the natural gas from our wells is connected to pipeline systems.

During 2011, we increased our standard number of fracture stimulation stages per well from approximately 24 stages to 30 stages. Although there are always overriding geologic factors that influence production, we believe the increase in our estimated average recoverable reserves per well from 518 MBoe gross to 603 MBoe gross in 2011 can be attributed primarily to the increased number of fracture stimulation stages used per well. We continually monitor results and modify our fracture stimulation techniques to maximize the amount of crude oil we recover from the reservoirs.

During 2012, we plan to invest approximately $950 million drilling 470 gross (114.6 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 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 the North Dakota Bakken field will eventually be developed on 320-acre spacing like the Elm Coulee field in Montana. As of February 15, 2012, we had 19 operated rigs drilling in the North Dakota Bakken and plan to operate 21 rigs drilling in the play through most of 2012.

Montana Bakken. Our Montana Bakken production is located primarily in the Elm Coulee field in Richland County, Montana. The Elm Coulee field was listed by the Energy Information Administration in 2010 as the 17th largest onshore field in the lower 48 states of the United States ranked by 2009 proved liquid reserves. During 2011 we completed 21 gross (12.8 net) wells, bringing our total number of wells drilled in the Montana Bakken to 193 gross (122.1 net) wells as of December 31, 2011. Our production increased to an average rate of 5,971 net Boe per day during the month of December 2011, up 26% from the average daily rate in December 2010. As of December 31, 2011 our Montana Bakken properties represented 9% of our PV-10 and 8% of our average daily Boe production for the three months ended December 31, 2011. During the year we added 36,278 gross (20,339 net) acres in the Montana Bakken play. As of December 31, 2011, we owned 347,790 gross (252,626 net) acres, of which 30% of the net acreage is developed and the remaining 70% of the net acreage is undeveloped.

2011 was a breakthrough year for us in the Montana Bakken as we successfully began to expand and develop the Elm Coulee field using state of the art drilling and completion technology. Areas once considered non-commercial based on old open hole completion technology have now proved to be commercial using cased hole, multi-stage fracture stimulation technology. During 2011 we completed 15 gross (12.3 net) wells in the immediate Elm Coulee field area. These wells included in-field, step-out and strategic exploratory wells that were completed flowing at initial 24 hour rates of up to 1,163 Boe per day. Based on the 2011 drilling program, the productive limits of the Elm Coulee field were expanded 2 to 5 miles to the north onto portions of our undeveloped leasehold.

We plan to invest approximately $90.7 million drilling 18 gross (11.6 net) wells in the Montana Bakken during 2012. Our drilling will focus on in-field development and continued expansion of the Elm Coulee field onto our undeveloped acreage north of the field. As of February 15, 2012, we had 3 rigs drilling in the Montana Bakken and plan to maintain 3 rigs in the play through most of 2012. As of December 31, 2011, we had 81 gross (50.0 net) proved undeveloped locations identified in the Montana Bakken.

Red River Units

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 2010 as the 9th largest onshore field in the lower 48 states of the United States ranked by 2009 liquid proved reserves.

Our Red River units represented 22% of our PV-10 as of December 31, 2011 and 20% of our average daily Boe production for the three months ended December 2011. Production from these legacy properties increased 5% in 2011 compared to 2010 due to new wells being completed and enhanced recovery techniques being successfully applied. For the month of December 2011, total production from the units averaged 14,925 Boe per day, an increase of 9% from average daily production in December 2010. Proved reserves grew 18% year-over-year to 64 MMBoe as of December 31, 2011. We are continuing to extend the peak performance life of our properties in the Red River units primarily by increasing our water and air injection capabilities and taking other measures to optimize production. As of December 31, 2011, we had 150,534 gross (131,428 net) acres in the Red River units, all of which is developed acreage.

In 2012, we plan to complete pattern drilling on the waterflood project in the Cedar Hills units and continue development activity in the Medicine Pole Hills units and Buffalo units. We have allocated $48.5 million of our 2012 capital expenditure budget to the Red River units, which will support one drilling rig and continued investment in facilities and infrastructure.

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Cedar Hills Units. The Cedar Hills North unit (CHNU) is located in Bowman and Slope Counties, North Dakota. We drilled the initial horizontal well in CHNU, the Ponderosa 1-15, in April 1995. As of December 31, 2011, we had drilled 238 horizontal wells within this 49,700-acre unit, with 117 producing wellbores and the remainder serving as injection wellbores. We own and operate a 96% working interest in the CHNU.

The Cedar Hills West unit (CHWU), in Fallon County, Montana, is contiguous to the northern portion of CHNU. As of December 31, 2011, this 7,800-acre unit contained 12 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 high-pressure air injection 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, we began to transition the units to 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 it is more economical to 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 11,401 Boe per day in December 2011. During 2012, we plan to complete the increased density drilling for both producing wells and injection wells. We plan to invest approximately $36.6 million during 2012 for capital workovers, facilities, and the drilling of 12 gross (11.5 net) wells in the Cedar Hills units.

Medicine Pole Hills Units. The three Medicine Pole Hills units (MPHU), consisting of the original MPHU, West MPHU, and South MPHU, are approximately five miles east of the southern portion of the CHNU and are located in Bowman County, North Dakota. We acquired the original 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 own and operate working interests of 62%, 92%, and 98% in the original MPHU, West MPHU, and South MPHU, respectively. Total production from the three units averaged 1,787 Boe per day during December 2011, 17% higher than average daily production in December 2010. In 2012, we plan to install a third electric driven air compressor (15 MMcf per day injection capacity) to replace the four remaining higher maintenance gas driven air compressors. We plan to invest approximately $6.4 million during 2012 for drilling, capital workovers, upgrading facilities, and other activities in the Medicine Pole Hills units.

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. We own and operate working interests of 97%, 97%, and 96% in the 33,000 acres comprising the Buffalo, West Buffalo, and South Buffalo units, respectively. When we purchased the three 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. From 2005 through 2011, we re-entered 46 existing vertical wells and drilled horizontal laterals to increase production and sweep efficiency from the three units. Total production from the three units for the month of December 2011 averaged 1,737 Boe per day, an increase of 22% from average daily production in December 2010. In 2012, we plan to invest approximately $5.5 million for capital workovers, upgrading facilities, and other activities in the Buffalo Red River units.

Niobrara

The Upper Cretaceous Niobrara formation has emerged as another potential crude oil resource play in various basins throughout the northern Rocky Mountain region including the DJ Basin of Colorado and Wyoming. 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. Historically, natural fracturing has played a key role in producing the Niobrara due to the low porosity and low permeability of the formation. Because of this, conventional production has been very localized and limited in extent. We believe the Niobrara can be produced on a more widespread basis using horizontal multi-stage fracture stimulation technology where the Niobrara is thermally mature.

DJ Basin. The DJ Basin Niobrara play emerged as a potential crude oil resource play in 2010 and attracted a flurry of leasing activity based on drilling results announced early in 2010. Since that time, approximately 161 horizontal Niobrara wells have been reported as completed with initial production rates of up to 1,665 Boe per day. The most consistent results have been reported on the Colorado portion of the DJ Basin, particularly Weld County Colorado. As of December 31, 2011, we owned 154,799 gross (93,339 net) acres in the DJ Basin Niobrara play. Approximately 37% of the net acreage is located in Weld and Morgan Counties, Colorado and 63% in Laramie, Goshen and Platte Counties in Wyoming.

During 2011, we drilled our first horizontal Niobrara wells in the DJ Basin and as of February 15, 2012, we have completed 5 gross (3.6 net) Niobrara wells. Results have varied which is typical in the early stages of any play as we refine our geologic model and completion techniques. Thus far, the Staudinger 1-31H (56% WI) is our best performing well, producing 736 Boe per day during its initial 24 hour test period. Early performance of the Staudinger 1-31H is encouraging and in line with our economic model for the play. Of note, we continue to be a leader with technology as our Staudinger 1-31H and Newton 1-4H wells were the first 1,280-acre unit wells drilled in the play. During 2011 we acquired 92 square miles of 3D seismic data to guide future drilling.

In 2012, we plan to invest approximately $59 million to drill 26 gross (12.0 net) wells in the DJ Basin Niobrara play. This drilling will continue to be focused in Weld County, Colorado. The drilling will include step-out and exploratory wells that are strategically located to de-risk our acreage.

South Region

Our properties in the South region represented 12% of our PV-10 as of December 31, 2011 and 22% of our average daily Boe production for the three months ended December 31, 2011. During the three months ended December 31, 2011, our average daily production from such properties was 2,316 net Bbls of crude oil and 85,631 net Mcf of natural gas, up 82% from the same period in 2010. 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 11% of our PV-10 as of December 31, 2011 and 18% of our net average daily Boe production for the three months ended December 31, 2011. Production from the Oklahoma Woodford for 2011 totaled 3,548 MBoe (21,288 MMcfe), up 84% over 2010. Production increased throughout the year, and the average daily production for our Oklahoma Woodford properties for the month of December 2011 was 15,026 Boe per day, up 145% over our daily average production for the month of December 2010. As of December 31, 2011, we held 617,313 gross (332,162 net) acres in the play. As of December 2011, 25% of the net acreage is developed and the remaining 75% of the net acreage is undeveloped.

During 2011 we completed 121 gross (46.6 net) Oklahoma Woodford wells. During 2012, we plan to invest approximately $356.1 million drilling 160 gross (46.6 net) wells in the Oklahoma Woodford. As of February 15, 2012 we had 12 rigs drilling in the Oklahoma Woodford and plan to operate 10 rigs in the play through most of 2012.

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Anadarko Woodford. The Anadarko Woodford represented 9% of our PV-10 as of December 31, 2011 and 13% of our average daily Boe production for the three months ended December 31, 2011. Our Anadarko Woodford production grew 367% year-over-year due to our increased drilling activity in 2011. During the month of December 2011, our Anadarko Woodford production averaged 10,675 net Boe per day, up 465% over our average daily production in December 2010.

Over the past 2 years, the Anadarko Woodford play has developed into an established resource play that appears to cover at least 1,800 square miles (1,152,000 acres) along the eastern flank of the Anadarko Basin. We control one of the largest acreage positions in the Anadarko Woodford play, with 444,345 gross (278,116 net) acres under lease as of December 31, 2011. This acreage is located in Canadian, Blaine, Dewey, Caddo, Grady and McClain counties in Oklahoma, extending approximately 50 miles northwest and 75 miles southeast from the Cana field area, where the initial discovery was made in late 2007. Approximately 65% of our acreage is located in our Northwest Cana project and 35% is located in our Southeast Cana project.

During 2011, we accelerated our drilling program and completed 103 gross (41.8 net) wells as compared to 16 gross (8.2 net) wells in 2010. Our 2011 drilling program was designed to expand the known extents of Anadarko Woodford production on our acreage. Under this program, we successfully completed strategic wells in both our Northwest Cana and Southeast Cana projects and de-risked more of our acreage in the play. In particular, the Lambakis 1-11H (98% WI) and the Lyle 1-30H (99%WI) wells in Southeast Cana established commercial production 30 miles south of the known limit of Woodford production at year-end 2010. Both wells are exceptional wells producing a combination of oil, natural gas and natural gas liquids. The Lambakis 1-11H produced 5.4 MMcf of natural gas and 160 Bbls of crude oil per day during its initial 24 hour test period. The Lyle 1-30H produced 7.1 MMcf of natural gas and 325 Bbls of crude oil per day during its initial 24 hour test period. The high liquids content of the natural gas is significant as it increases the overall value of the production due to the higher BTU content of the natural gas.

In February 2012, we completed the first cross-unit well drilled in the Anadarko Woodford play. The Toms 1-21XH (90% WI) in Blaine County, Oklahoma produced 1.9 MMcf per day and 965 Bbls per day during its initial 24 hour test period. The well was drilled to a total depth of 20,523 feet and included a 9,500 foot lateral, which is approximately twice the length of a typical horizontal Anadarko Woodford well. Cross-unit spaced drilling is significant because it allows operators to access two spacing units from a single long wellbore. From our experience, we expect the longer laterals will reduce costs, increase well productivity and enhance the overall economics of the play. We are very encouraged by the results of our first cross-unit well and expect to increase the use of this technology as we develop the field.

During 2011, we acquired approximately 600 square miles of proprietary 3D seismic data. Acquiring this data was a critical step in the development of the Northwest Cana and Southeast Cana projects as the data will be used to guide our drilling for years to come. Another critical development in 2011 was the increased pipeline capacity to transport natural gas from the Northwest Cana area. Curtailments experienced in 2011 should be eliminated in 2012 as a result of new pipeline infrastructure scheduled for operation in early 2012.

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. To date, approximately one third of our Woodford wells have encountered indications of productive reservoirs in overlying Tonkawa, Red Fork, Morrow, Springer and/or Mississippian reservoirs, while drilling to the Woodford shale.

In 2012, we plan to invest approximately $354.5 million to drill 159 gross (46.1 net) wells to further delineate and develop the Anadarko Woodford on our acreage. As of February 15, 2012, we had 12 operated rigs drilling in the Anadarko Woodford play and plan to operate 10 rigs in the play through most of 2012. To support our drilling program, we expect to invest approximately $11.9 million to acquire approximately 350 square miles of proprietary 3D seismic to guide future drilling on our acreage. As of December 31, 2011, we had a total of 251 gross (120.1 net) proved undeveloped locations identified on our Anadarko Woodford acreage.

Arkoma Woodford. The Arkoma Woodford represented 2% of our PV-10 as of December 31, 2011 and 5% of our average daily Boe production for the three months ended December 31, 2011. Year-over-year, Arkoma Woodford production was down 6% due to our scaled back drilling program in 2011. As of December 31, 2011 we have completed a total of 367 gross (59.7 net) wells in the Arkoma Woodford play.

In 2011, we slowed our pace of drilling in the Arkoma Woodford as available capital was redirected to the more liquid-rich Anadarko Woodford. During the year we completed a total of 18 gross (4.8 net) wells, as compared to 50 gross (6.5 net) wells in 2010. The wells were focused primarily on our East McAlester acreage and produced up to 5,055 Mcf per day during their initial 24 hour test period. As of December 31, 2011, we owned approximately 132,898 gross (39,594 net) acres in the Arkoma Woodford play, of which 63% of our net acreage is developed and the remaining 37% of our net acreage is undeveloped.

In 2011, we removed 21.9 MMBoe of proved undeveloped reserves from our Arkoma Woodford district, representing 213 gross (44.8 net) PUD locations. We had planned to develop these PUD reserves by year-end 2013. However, given current and projected prices for natural gas, we elected to defer drilling and therefore declassified these PUD reserves. A remaining total of 97 gross (46.5 net) PUD locations, representing 26.0 MMBoe of remaining PUD reserves, have been identified on this acreage as of December 31, 2011. In 2012, we plan to finish wells in progress at year-end 2011 but plan to defer any further drilling until natural gas prices improve. We expect to invest approximately $1.6 million to drill 1 gross (0.5 net) well in the Arkoma Woodford play during 2012.

East Region

Our properties in the East region represented 1% of our PV-10 as of December 31, 2011. During the three months ended December 31, 2011, our average daily production from such properties was 1,178 net Boe per day. Our principal producing properties in this region are located in the Illinois Basin and Michigan Basin in the eastern United States. We continue to maximize the performance of these properties through workovers, recompletions and drilling as warranted. As of December 31, 2011, we had 69,042 gross (49,545 net) acres in the Trenton-Black River area of Michigan, of which 1% of the net acreage is developed and 99% of the net acreage is undeveloped. Drilling on these properties has been guided by our proprietary 3D seismic data. We currently own 64 square miles of 3D seismic data on the properties and have numerous potential drilling locations identified for future drilling. In 2012, we plan to acquire an additional 30 square miles of 3D seismic to identify additional opportunities for drilling.

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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, 2011, 2010 and 2009 in total and for each field containing 15 percent or more of our total proved reserves as of December 31, 2011:

	Year Ended December 31,		
	2011	2010	2009
Net production volumes:			
Crude oil (MBbls) (1)			
North Dakota Bakken	8,480	4,450	2,257
Anadarko Woodford	267	56	15
Total Company	16,469	11,820	10,022
Natural gas (MMcf)			
North Dakota Bakken	7,523	3,994	1,729
Anadarko Woodford	11,422	2,451	554
Total Company	36,671	23,943	21,606
Crude oil equivalents (MBoe)			
Total Company	22,581	15,811	13,623
Average sales prices: (2)			
Crude oil ($/Bbl)			
North Dakota Bakken	$ 88.43	$ 70.09	$ 55.06
Anadarko Woodford	92.14	77.68	60.80
Total Company	88.51	70.69	54.44
Natural gas ($/Mcf)			
North Dakota Bakken	7.18	6.38	4.73
Anadarko Woodford	5.27	4.63	3.95
Total Company	5.24	4.49	3.22
Crude oil equivalents ($/Boe)			
Total Company	73.05	59.70	45.10
Costs and expenses: (2)			
Production expenses ($/Boe)			
North Dakota Bakken	$ 4.05	$ 2.94	$ 3.64
Anadarko Woodford	1.95	1.52	1.88
Total Company	6.13	5.87	6.89
Production taxes and other expenses ($/Boe)	6.42	4.82	3.37
General and administrative expenses ($/Boe) (3)	3.23	3.09	3.03
DD&A expense ($/Boe)	17.33	15.33	15.34

(1) Crude oil sales volumes differ from production volumes because, at various times, we have stored crude oil in inventory due to pipeline line fill requirements, low commodity prices, or transportation constraints or we have sold crude oil from inventory. Crude oil sales volumes were 30 MBbls less than production volumes for the year ended December 31, 2011, 78 MBbls more than production volumes for the year ended December 31, 2010 and 82 MBbls less than production volumes for the year ended December 31, 2009.

(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 $0.73 per Boe, $0.74 per Boe, and $0.84 per Boe for the years ended December 31, 2011, 2010 and 2009, respectively.

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The following table sets forth information regarding our average daily production by region during the fourth quarter of 2011:

	Fourth Quarter 2011 Daily Production		
	Crude Oil (Bbls per day)	Natural Gas (Mcf per day)	Total (Boe per day)
North Region:			
Bakken field			
North Dakota Bakken	30,691	29,245	35,565
Montana Bakken	4,884	4,764	5,678
Red River units			
Cedar Hills	11,276	3,048	11,784
Other Red River units	3,070	2,352	3,462
Other	608	2,136	964
South Region:			
Oklahoma Woodford			
Anadarko Woodford	1,414	50,437	9,820
Arkoma Woodford	21	22,004	3,688
Other	881	13,190	3,080
East Region	1,060	707	1,178
Total	53,905	127,883	75,219

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, 2011:

	Crude Oil Wells		Natural Gas Wells		Total Wells	
	Gross	Net	Gross	Net	Gross	Net
North Region:						
Bakken field						
North Dakota Bakken	884	291	6	1	890	292
Montana Bakken	216	137	2	1	218	138
Red River units	267	242	2	2	269	244
Other	227	209	6	2	233	211
South Region:						
Oklahoma Woodford						
Anadarko Woodford	12	7	119	49	131	56
Arkoma Woodford			387	57	387	57
Other	220	173	249	124	469	297
East Region	645	519	13	11	658	530
Total	2,471	1,578	784	247	3,255	1,825

As of December 31, 2011, 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 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

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substantially all of our producing properties and believe 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

Most of our crude oil production is sold 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 pipeline gathering systems, although the balance of our production is transported by truck or rail. Where 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 sold at the lease is delivered directly onto the purchasers truck and the sale is complete at that point.

As a result of pipeline constraints and the continuous increase in Williston Basin production, in December 2011 we transported approximately 30% of the crude oil production from our North region by rail. We are using both manifest and unit train facilities for these shipments and anticipate these shipments will continue.

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. Some of our 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 *Part I, Item 1A. Risk factors Our business depends on crude oil and natural gas transportation facilities, most of which are owned by third parties, and on the availability of rail transportation.*

For the years ended December 31, 2011, 2010 and 2009, crude oil sales to Marathon Crude Oil Company accounted for approximately 41%, 57% and 56% of our total revenues, respectively. No other purchaser accounted for more than 10% of our total crude oil and natural gas sales for 2011, 2010 and 2009. We believe the loss of our largest purchaser would not have a material adverse effect on our operations, as crude oil and natural gas are fungible products with well-established markets and numerous purchasers in our producing regions.

Competition

We operate in a highly competitive environment for acquiring properties, marketing crude oil and natural gas and securing trained personnel. Our competitors vary within the regions in which we operate, and some of our competitors may possess and employ financial, technical and personnel resources 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, equipment or other services could delay or adversely affect our development and exploration operations. Our ability to acquire additional prospects and to find and develop reserves in the future will depend on our ability to evaluate and select suitable properties and to consummate transactions in a highly competitive environment. Also, there is substantial competition for capital available for investment in the crude oil and natural gas industry.

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Regulation of the Crude Oil and Natural Gas Industry

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 we are in substantial compliance with all laws and regulations currently applicable to our operations and 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 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 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 Sales and Transportation of Crude Oil and Natural Gas Liquids

Sales of crude oil and natural gas liquids or condensate (NGLs) are not currently regulated and are made at negotiated prices. Nevertheless, the U.S. Congress could enact price controls in the future. With regard to our physical sales of crude oil and derivative instruments relating to crude oil, we are required to comply with 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 and NGLs, as well as other liquid products, is subject to rate and access regulation. The Federal Energy Regulatory Commission (FERC) regulates interstate crude oil and NGL pipeline transportation rates under the Interstate Commerce Act. In general, such 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 and NGL pipeline transportation rates may be subject to regulation by state regulatory commissions. The basis for intrastate 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 the regulation of intrastate 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 pipelines and intrastate common carrier pipelines must provide service on an equitable basis. Under this standard, such pipelines must offer service to all similarly situated shippers requesting service on the same terms and under the same rates. When such pipelines operate at full capacity, access is governed by prorating provisions set forth in the pipelines published tariffs. Accordingly, we believe we generally will have access to crude oil pipeline transportation services to the same extent as to our similarly situated competitors.

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Regulation of Sales and Transportation of Natural Gas

In 1989, the U.S. Congress enacted the Natural Gas Wellhead Decontrol Act, which removed all remaining price and non-price controls affecting wellhead sales of natural gas effective January 1, 1993. The FERC, which has the authority under the Natural Gas Act (NGA) to regulate prices, terms, and conditions for the sale of natural gas for resale in interstate commerce, has issued blanket authorizations for all gas resellers subject to FERC regulation, except interstate pipelines, to resell natural gas at market prices. However, either the U.S. Congress or the FERC (with respect to the resale of gas in interstate commerce) could re-impose price controls in the future.

The FERC regulates interstate natural gas transportation rates and service conditions under the NGA and the Natural Gas Policy Act of 1978 (NGPA), which affects the marketing of natural gas we produce, as well as revenues we receive for sales of our natural gas. 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 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 services 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 any action taken will affect us in a materially different way than other natural gas producers.

With regard to our physical sales of natural gas and derivative instruments 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 various FERC orders,we may be required to submit reports to the FERC for some of our operations. 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 natural gas to point of sale locations. State regulation of natural gas gathering facilities generally includes 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 we would be affected by any such regulatory changes in a materially different way than our similarly situated 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 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 the regulation of similarly situated intrastate natural gas transportation in 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 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.

Other Federal Laws and Regulations Affecting Our Industry

Dodd-Frank Wall Street Reform and Consumer Protection Act. In July 2010, the Dodd-Frank Wall Street Reform and Consumer Protection Act (the Dodd-Frank Act) was enacted into law. This financial reform legislation includes provisions that require over-the-counter derivative transactions to be executed through an exchange or centrally cleared. The Dodd-Frank Act requires the CFTC, the SEC, and other regulators to establish rules and regulations to implement the new legislation. The CFTC has issued final regulations to implement significant aspects of the legislation, including new rules for the registration of swap dealers and major swap participants, requirements for reporting and recordkeeping, rules on customer protection in the context of cleared swaps, and position limits for swaps and other transactions based on the price of certain reference contracts, some of which are referenced in our swap contracts. Key regulations that have not yet been finalized include those clarifying the definitions of swap dealer, major swap participant and swap and those establishing margin requirements for uncleared swaps and various trade execution and trade documentation requirements. These regulations may require or cause our counterparties to collect margin from us and may require us to clear our transactions or execute them on a derivatives contract market or swap execution facility, although the application of those provisions to us is uncertain at this time. The ultimate effect of the proposed new rules and any additional regulations on our business is uncertain. Of particular concern is whether the provisions of the final rules and regulations will allow us to qualify as a non-financial, commercial end user that is exempt from the requirement to clear our derivative contracts, and whether our status will allow our derivative counterparties to not require us to post margin in connection with our commodity price risk management activities. The remaining final rules and regulations on major provisions of the legislation, such as new margin requirements, are to be established through regulatory rulemaking. Although we cannot predict the ultimate outcome of these rulemakings, new rules and regulations in this area, 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 manage our financial and commercial risks related to fluctuations in commodity prices, increased regulatory reporting and recordkeeping, and market dislocations or disruptions, among other consequences, and could have an adverse effect on our ability to hedge risks associated with our business.

Energy Policy Act of 2005. The Energy Policy Act of 2005 (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 NGA to add an anti-market manipulation provision that 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. In January 2006, the FERC issued rules implementing the anti-market manipulation provision of EPAct 2005. These anti-market manipulation rules apply to activities of natural 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 natural gas sales, purchases or transportation subject to FERC jurisdiction, which now includes the annual reporting requirements as 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 NGPA. Under EPAct 2005, the FERC also has authority to order disgorgement of profits associated with any violation. The anti-market manipulation rules and enhanced civil penalty authority reflect an expansion of the FERC s enforcement authority.

FERC Market Transparency and Reporting Rules. The FERC requires wholesale buyers and sellers of more than 2.2 million MMBtus 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, 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. The FERC 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 and CFTC 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, including authority to request that a court impose fines of up to $1,000,000 per day per violation. Under the Commodity Exchange Act, the CFTC is directed to prevent price manipulations for the commodity and futures markets, including the energy futures markets. Pursuant to the Dodd-Frank Act, the CFTC has adopted anti-market manipulation regulations that prohibit, among other things, fraud and price manipulation in the commodity and futures markets. The CFTC also has statutory authority to assess fines of up to $1,000,000 for violations of its anti-market manipulation regulations**.**

Additional proposals and proceedings that might affect the crude oil and natural gas industry are pending before the U.S. 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 we would be affected by any such action materially different than similarly situated competitors.

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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 a rate that would otherwise be possible. The regulatory burden on the crude oil and natural gas industry increases the cost of doing business and affects profitability. Additionally, the U.S. 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 we 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), the cleanup of property contamination (including groundwater contamination), and remedial plugging operations to prevent future contamination; (iii) 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 statutes; (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 and comparable state statutes, which require government 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 are included within our overall capital and operating budgets and are not separately itemized. Although we believe 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 the emission of carbon dioxide and other identified greenhouse gases may have on the environment and climate worldwide. These effects are widely referred to as climate change. Since its December 2009 endangerment finding regarding the emission of carbon dioxide, methane and other greenhouse gases, the EPA has begun regulating sources of greenhouse gas emissions under the federal Clean Air Act. Among several regulations requiring reporting or permitting for greenhouse gas sources, the EPA finalized its tailoring rule in May 2010 that determines which stationary sources of greenhouse gases 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 November 2010, the EPA also finalized its greenhouse gas reporting requirements, beginning in March 2012, for certain oil and gas production facilities that emit 25,000 metric tons or more of carbon dioxide equivalent per year.

Moreover, in recent past the U.S. Congress has considered establishing a cap-and-trade program to reduce U.S. emissions of greenhouse gases, including carbon dioxide and methane. Under past 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 ever adopted, would be to impose increasing costs on the combustion of carbon-based fuels such as crude oil, refined petroleum products, and natural gas. In addition, while the prospect for such cap-and-trade legislation by the U.S. Congress remains uncertain, several states, including states in which we operate, have adopted, or are in the process of adopting, similar cap-and-trade programs.

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 we sell, emits carbon dioxide and other greenhouse gases. Thus, any current or future federal, state or local climate change initiatives could adversely affect demand for the crude oil and natural gas we produce by stimulating demand for alternative forms of energy that do not rely on the combustion of fossil fuels, and therefore could have a material adverse effect on our business. Although our compliance with any greenhouse gas regulations may result in increased compliance and operating costs, we do not expect the compliance costs for currently applicable regulations to be material. Moreover, while it is not possible at this time to estimate the compliance costs or operational impacts for any new legislative or regulatory developments in this area, we do not anticipate being impacted to any greater degree than other similarly situated competitors.

Hydraulic fracturing. Hydraulic fracturing involves the injection of water, sand and additives under pressure into rock formations to stimulate crude oil and natural gas production. Some activists have attempted to link hydraulic fracturing to various environmental problems, including adverse effects to drinking water supplies and migration of methane and other hydrocarbons. As a result, several federal agencies are studying the environmental risks with respect to hydraulic fracturing or evaluating whether to restrict its use. From time to time, legislation has been introduced in the U.S. Congress to amend the federal Safe Drinking Water Act to eliminate an existing exemption for hydraulic fracturing activities from the definition of underground injection, thereby requiring the crude oil and natural gas industry to obtain permits for hydraulic fracturing and to require disclosure of the additives used in the process. If ever adopted, such legislation could establish an additional level of regulation and permitting at the federal level. Scrutiny of hydraulic fracturing activities continues in other ways, with the EPA having commenced a multi-year study of the potential environmental impacts of hydraulic fracturing, the initial results of which are anticipated to be available by late 2012. The U.S. Department of the Interior has announced it will publish rules requiring companies to disclose the make-up of all materials used in hydraulic fracturing fluids on federal lands. The announced legislation will also require disclosure of the source, access route and transport of all water anticipated to be used in connection with hydraulic fracturing operations. The announced rules have not been published and we are not able to determine the extent of their impact on our operations on federal land. In addition to these federal initiatives, several state and local governments, including states in which we operate, have moved to require disclosure of fracturing fluid components or otherwise to regulate their use more closely. In certain areas of the United States, new drilling permits for hydraulic fracturing have been put on hold pending development of additional standards. The adoption of any future federal, state or local laws or implementing regulations imposing permitting or reporting obligations on, or otherwise limiting, the hydraulic fracturing process could make it more difficult and more expensive to complete crude oil and natural gas wells in low-permeability formations, increase our costs of compliance and doing business, and delay, prevent or prohibit the development of natural resources from unconventional formations. 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. At this time it is not possible to estimate the potential impact on our business if this federal or state legislation is enacted into law.

Employees

As of December 31, 2011, we employed 609 people, including 343 employees in drilling and production. 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 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 website 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 any amendments to those reports as soon as reasonably practicable after the report is filed with or furnished to the SEC. For a current version of various corporate governance documents, including our Code of Ethics, please see our website. We intend to disclose amendments to, or waivers from, our Code of Ethics by posting to our website. Information contained on our website is not incorporated by reference into this report and you should not consider information contained on our website as part of this report.

We intend to use our website as a means of disclosing material information and for complying with our disclosure obligations under SEC Regulation FD. Such disclosures will be included on our website in the For Investors section. Accordingly, investors should monitor that portion of our website in addition to following our press releases, SEC filings and public conference calls and webcasts.

We file periodic reports and proxy statements with the SEC. The public may read and copy any materials we file with the SEC at the SEC s Public Reference Room at 100 F Street N.E., Washington, D.C. 20549. The public may obtain information about the operation of the Public Reference Room by calling the SEC at 1-800-SEC-0330. We file our reports with the SEC electronically. The SEC maintains an internet website 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 *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.

Item 1A. Risk Factors

You should carefully consider each of the risks described below, together with all 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 our business activities. 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

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currently known to us or, as a result of developments occurring in the future. Further, conditions we currently deem to be immaterial may also materially and adversely affect our business, financial condition, cash flows, and results of operations in the future.

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, but are not limited to, 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;
- 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;
- the level of national and global crude oil and natural gas exploration and production;
- the level of national and 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.

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 we can economically produce.

Substantial, extended 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 significant downward adjustments to our estimated proved reserves. As a result, a substantial, extended decline in crude oil or natural gas prices would materially and adversely affect our future business, financial condition, results of operations, liquidity or ability to finance planned capital expenditures.

A substantial portion of our producing properties are located in the North region, making us vulnerable to risks associated with having operations concentrated in this geographic area.

Because our operations are geographically concentrated in the North region (76% of our production in the fourth quarter of 2011 was from the North region), the success and profitability of our operations may be disproportionally exposed to the effect of regional events. These include, among others, fluctuations in the prices of crude oil and natural gas produced from wells in the region and other regional supply and demand factors, including gathering, pipeline and other transportation capacity constraints, available rigs, equipment, oil field services, supplies, labor and infrastructure capacity. In addition, our operations in the North region may be adversely affected by seasonal weather and lease stipulations designed to protect wildlife, which can intensify

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competition for the items described above during months when drilling is possible and may result in periodic shortages. The concentration of our operations in the North region also increases exposure to unexpected events that may occur in this region such as natural disasters or labor difficulties. Any one of these events has the potential to cause producing wells to be shut-in, delay operations and growth plans, decrease cash flows, increase operating and capital costs and prevent development of lease inventory before expiration. Any of the risks described above could have a material adverse effect on our financial condition and results of operations.

Volatility in the financial markets or in global economic factors could adversely impact our business and financial condition.

In recent years, U.S. and global economies and financial systems have experienced turmoil and upheaval characterized by extreme volatility and declines in prices of securities, diminished liquidity and credit availability, inability to access capital markets, the bankruptcy, failure, collapse or sale of financial institutions, increased levels of unemployment and an unprecedented level of intervention by the U.S. federal government and other governments. Although some portions of the economy appear to have stabilized, and there have been signs of the beginning of recovery, the extent and timing of a recovery, and whether it can be sustained are uncertain. Continued economic weakness or uncertainty could reduce demand for crude oil and natural gas and put downward pressure on the prices of crude oil and natural gas. This would negatively impact our revenues, margins, profitability, operating cash flows, liquidity and financial condition. Such weakness or uncertainty could also cause our commodity hedging arrangements to become economically ineffective if our counterparties are unable to perform their obligations or seek bankruptcy protection. Furthermore, our ability to collect receivables may be adversely impacted.

Historically, we have used cash flows from operations, borrowings under our revolving credit facility and capital market transactions to fund capital expenditures. 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. We have an existing revolving credit facility with lender commitments totaling $1.25 billion and a borrowing base of $2.25 billion as of February 15, 2012. In the future, we may not be able to access adequate funding under our bank credit facility 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 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 reserves, take advantage of business opportunities, respond to competitive pressures, or refinance debt obligations as they come due.

Should any one of the above risks occur, it could have a material adverse effect on our financial condition and results of operations.

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 and production.

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 exploration, development, exploitation, production and acquisition of crude oil and natural gas reserves. In 2011, we invested $2.2 billion in our capital program. Our capital expenditures for 2012 are budgeted to be $1.75 billion with $1.63 billion allocated for drilling, capital workovers and facilities. To date, these capital expenditures have been financed with cash generated by operations, borrowings under our revolving credit facility and the issuance of debt and equity securities. The actual amount and timing of 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,

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and regulatory, technological and competitive developments. Continued improvement in commodity prices may result in an increase in actual capital expenditures. Conversely, a significant decline in commodity prices could result in a decrease in capital expenditures. We intend to finance future capital expenditures primarily through cash flows from operations and 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 requires 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 needs, 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:

- the amount of 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 crude oil and natural gas are sold;
- our ability to acquire, locate and produce new reserves; and
- the ability of our banks to extend credit.

If 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 capital requirements, the failure to obtain additional financing could result in a curtailment of 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 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 may be uncertain before drilling commences.

Risks we face while drilling include, but are not limited to, failing to place our well bore in the desired target producing zone; not staying in the desired drilling zone while drilling horizontally through the formation; failing to run our casing the entire length of the well bore; and not being able to run tools and other equipment consistently through the horizontal well bore. Risks we face while completing our wells include, but are not limited to, not being able to fracture stimulate the planned number of stages; failing to run tools the entire length of the well bore during completion operations; and not successfully cleaning out the well bore after completion of the final fracture stimulation stage.

Further, many factors may curtail, delay or cancel scheduled drilling projects, including;

- abnormal pressure or irregularities in geological formations;

shortages of or delays in obtaining equipment and qualified personnel;

mechanical difficulties, fires, explosions, ruptures of pipelines, equipment failures or accidents;

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- adverse weather conditions and natural disasters, such as flooding, blizzards and ice storms;
- reductions in crude oil and natural gas prices;
- limited availability of financing with acceptable terms;
- title problems;
- environmental hazards, such as uncontrollable flows of crude oil, natural gas, brine, well fluids, hydraulic fracturing fluids, toxic gas or other pollutants into the environment, including groundwater and shoreline contamination;
- spillage or mishandling of crude oil, natural gas, brine, well fluids, hydraulic fracturing fluids, toxic gas or other pollutants by third party service providers;
- limitations in infrastructure, including transportation capacity or in the market for crude oil and natural gas; and
- delays imposed by or resulting from compliance with regulatory requirements.

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 interpretation of available technical data and many assumptions, including assumptions relating to current and future economic conditions and commodity prices. Any significant inaccuracy in these interpretations or assumptions could materially affect our estimated quantities and present value of our reserves. See *Part I, Item 1. Business Crude Oil and Natural Gas Operations, Proved Reserves* for information about our estimated crude oil and natural gas reserves, PV-10, and Standardized Measure of discounted future net cash flows as of December 31, 2011.

In order to prepare 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 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. In accordance with SEC rules, we base the estimated discounted future net revenues from 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 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.

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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 our reserves or the crude oil and natural gas industry in general.

Actual future prices and costs may materially differ from those used in the present value estimate. If crude oil prices decline by $10.00 per barrel, our PV-10 as of December 31, 2011 would decrease approximately $1.3 billion. If natural gas prices decline by $1.00 per Mcf, our PV-10 as of December 31, 2011 would decrease approximately $594 million.

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

One of our business strategies is to commercially develop unconventional crude oil and natural gas resource plays using enhanced recovery technologies. For example, we inject water and high-pressure air into formations on some of our properties to increase the production of crude oil and natural gas. The additional production and reserves attributable to the use of these enhanced recovery methods are inherently difficult to predict. If enhanced recovery programs do not allow for the extraction of crude oil and natural gas in the manner or to the extent 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 could adversely affect our cash flows and results of operations.

Unless we conduct successful exploration, development and exploitation activities or acquire properties containing proved reserves, our proved reserves will decline as those reserves are produced. Producing crude oil and natural gas reservoirs are generally 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 our current reserves and economically finding or acquiring additional recoverable reserves. We may not be able to develop, 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 could 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 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 not provided for in our capital budget, which could have a material adverse effect on our business, financial condition or results of operations.

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

We are not insured against all risks. Losses and liabilities arising from uninsured and underinsured events could materially and adversely affect our business, financial condition or results of operations. Our crude oil and natural gas exploration and production activities are subject to all of the operating risks associated with drilling for and producing crude oil and natural gas, including the possibility of:

- environmental hazards, such as uncontrollable flows of crude oil, natural gas, brine, well fluids, hydraulic fracturing fluids, toxic gas or other pollutants 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;
- natural disasters; and
- spillage or mishandling of crude oil, natural gas, brine, well fluids, hydraulic fracturing fluids, toxic gas or other pollutants by third party service providers.

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 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 we decide to drill may not yield crude oil or natural gas in economically producible quantities.

Prospects we decide to drill that do not yield crude oil or natural gas in economically producible quantities may adversely affect our results of operations and financial condition. In this report, we describe some of our current prospects and 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. It is not possible to predict with certainty 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 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.

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

Our management has specifically identified and scheduled drilling locations as an estimation of our future multi-year drilling activities on our existing acreage. These drilling locations represent a significant part of our growth strategy. Our ability to drill and develop these locations depends on a number of uncertainties, including crude oil and natural gas prices, the availability of capital, costs, drilling results, regulatory approvals and other factors. 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 leases before they expire, any proved undeveloped reserves associated with such leases will be removed from our proved reserves. The combined net acreage expiring in the next three years represents 72% of our total net undeveloped acreage at December 31, 2011. At that date, we had leases representing 219,845 net acres expiring in 2012, 418,504 net acres expiring in 2013, and 245,396 net acres expiring in 2014. 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, and on the availability of rail transportation.

The marketability of our crude oil and natural gas production depends in part on the availability, proximity and capacity of pipeline and rail systems owned by third parties. The lack or unavailability of 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. 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 rail systems, labor disputes in the rail industry and general economic conditions could adversely affect our ability to produce, gather and transport crude oil and natural gas. As a result of pipeline constraints and the continuous increase in Williston Basin production, in December 2011 we transported approximately 30% of the crude oil production from our North Region by rail.

The disruption of third-party pipelines or rail transportation facilities due to labor disputes, maintenance and/or weather could negatively impact our ability to market and deliver our products. We have no control over when or if access to such pipeline or rail facilities will be restored or what prices will be charged. A significant shut-in of production in connection with any of the aforementioned items could materially affect our cash flows, and if a substantial portion of the impacted 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 developed and producing areas. 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 and local 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 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 *Part I, Item 1. Business Regulation of the Crude Oil and Natural Gas Industry* for a description of the laws and regulations that affect us.

Strict or joint and several liability may be imposed under certain laws, which could cause us to become liable for the conduct of others or for consequences of our own actions. 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 reduce demand for the crude oil, natural gas and natural gas liquids 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 the warming of the Earth s atmosphere and other climate changes. These findings by the EPA allow the agency to proceed with the adoption and implementation of several regulations that would restrict emissions of greenhouse gases under existing provisions of the federal Clean Air Act, such as the so-called tailoring rule adopted in May 2010, which imposes permitting and best available control technology requirements on the largest greenhouse gas stationary sources. In November 2010, the EPA also finalized its greenhouse gas reporting requirements, beginning in March 2012, for certain oil and gas production facilities that emit 25,000 metric tons or more of carbon dioxide equivalent per year. We currently estimate our producing wells in five basins will be subject to the reporting requirements.

In addition, the U.S. Congress has from time to time considered legislation to reduce emissions of greenhouse gases, and almost half of the states, including states in which we operate, have enacted or passed measures to reduce emissions of greenhouse gases, primarily through the planned development of greenhouse gas emission inventories and/or regional greenhouse gas cap-and-trade programs. Most of these cap-and-trade programs work by requiring either major sources of emissions or major producers of fuels to acquire and surrender emission allowances, with the number of allowances available for purchase reduced each year until the overall greenhouse gas emission reduction goal is achieved. These reductions may cause the cost of allowances to escalate significantly over time.

The adoption and implementation of regulations that require reporting of greenhouse gases or otherwise limit emissions of greenhouse gases from our equipment and operations could require us to incur costs to monitor and report on greenhouse gas emissions or reduce emissions of greenhouse gas associated with our operations. In addition, these regulatory initiatives could drive down demand for our products by stimulating demand for alternative forms of energy that do not rely on combustion of fossil fuels that serve as a major source of greenhouse gas emissions, which could have a material adverse effect on our business, financial condition and results of operations.

Finally, it should be noted 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, 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.

A significant majority of our operations utilize hydraulic fracturing, an important and commonly used process in the completion of crude oil and natural gas wells in low-permeability formations. Hydraulic fracturing involves the high-pressure injection of water, sand and additives into rock formations to stimulate crude oil and natural gas production. Some activists have attempted to link hydraulic fracturing to various environmental problems, including adverse effects to drinking water supplies as well as migration of methane and other hydrocarbons. As a result, several federal agencies are studying potential environmental risks with respect to hydraulic fracturing or evaluating whether to restrict its use. From time to time legislation has been introduced in the U.S. Congress to amend the federal Safe Drinking Water Act to eliminate an existing exemption for hydraulic fracturing activities from the definition of underground injection, thereby requiring the crude oil and natural gas industry to obtain permits for hydraulic fracturing, and to require disclosure of the additives used in the process. If ever adopted, such legislation could establish an additional level of regulation and permitting at the federal level. Scrutiny of hydraulic fracturing activities continues in other ways, with the EPA commencing a multi-year study of the potential environmental impacts of hydraulic fracturing, the initial results of which are anticipated to be available by late 2012. The U.S. Department of the Interior has announced it will publish rules requiring companies to disclose the make-up of all materials used in hydraulic fracturing fluids on federal lands. The announced legislation will also require disclosure of the source, access route and transport of all water anticipated to be used in connection with hydraulic fracturing operations. The announced rules have not been published and we are not able to determine the extent of their impact on our operations on federal land. At December 31, 2011, we held approximately 75,200 net undeveloped acres on federal land, representing approximately 6% of our total net undeveloped acres. In addition to these federal initiatives, several state and local governments, including states in which we operate, have moved to require disclosure of fracturing fluid components or to otherwise regulate their use more closely. In certain areas of the United States, new drilling permits for hydraulic fracturing have been put on hold pending development of additional standards.

The adoption of any future federal, state or local law or implementing regulation imposing permitting or reporting obligations on, or otherwise limiting, the hydraulic fracturing process, or the discovery of groundwater contamination or other adverse environmental effects directly connected to hydraulic fracturing, could make it more difficult and more expensive to complete crude oil and natural gas wells in low-permeability formations and increase our costs of compliance and doing business, as well as delay, prevent or prohibit the development of natural resources from unconventional formations. In the event regulations are adopted that prohibit or significantly limit the use of hydraulic fracturing in states in which we operate, it would have a material adverse effect on our ability to economically find and develop crude oil and natural gas reserves in our strategic plays. The inability to achieve a satisfactory economic return could cause us to curtail or discontinue our exploration and development plans. Such a circumstance would have a material adverse effect on our business and would impair our ability to implement our growth plan.

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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 or seek to impose through judicial action penalties for 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. The CFTC, under the Commodity Exchange Act, has similar authority to impose penalties of up to $1,000,000 for violation of anti-market manipulation rules for certain derivative contracts. In addition, while we have not been regulated by the FERC as a natural gas company under the NGA, the FERC has adopted regulations that may subject us to the FERC annual reporting requirements. Additional rules and legislation pertaining to those and other matters may be considered or adopted by the FERC from time to time. 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.

Proposed legislation under consideration 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 or the infrastructure used for transporting our products. This could result in increased operating costs and have a material adverse effect on our financial condition and results of operations. The U.S. Congress and various states are considering other 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 liquidity, delay operations or otherwise alter the way we conduct our business. This in turn, 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 2013 budget proposal, released by the White House in February 2012, are the elimination or deferral of certain key U.S. federal income tax deductions currently available to crude oil and natural gas exploration and production companies. Such proposed changes include, but are not limited to, (i) the repeal of the percentage depletion allowance for crude oil and gas properties; (ii) the elimination of current deductions for intangible drilling and development costs; (iii) the elimination of the deduction for certain production activities; and (iv) an extension of the amortization period for certain geological and geophysical expenditures. These proposed changes, if enacted, may negatively affect our financial condition and results of operations. The passage of legislation as a result of the proposed American Jobs Act 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 crude oil and natural gas exploration and development, and any such change could negatively affect our cash flows available for capital expenditures and our ability to achieve our growth plan.

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, the U.S. 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 CFTC, the

SEC, and in some cases banking regulators, to promulgate rules and regulations implementing the new legislation. The CFTC has issued final regulations to implement significant aspects of the legislation, including new rules for the registration of swap dealers and major swap participants, requirements for reporting and recordkeeping, rules on customer protection in the context of cleared swaps, and position limits for swaps and other transactions based on the price of certain reference contracts, some of which are referenced in our swap contracts. Key regulations not yet finalized include those clarifying the definitions of swap dealer, major swap participant and swap and those establishing margin requirements for uncleared swaps and various trade execution and trade documentation requirements as well as certain end-user exemptions. These regulations may require or cause our counterparties to collect margin from us and may require us to clear our transactions or execute them on a derivatives contract market or swap execution facility, although the application of those provisions to us is uncertain at this time. Some of the counterparties to our derivative instruments may also need or choose to spin off some of their derivatives activities to a separate entity, which may not be as creditworthy as our 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, lead to fewer potential counterparties, impose new recordkeeping and documentation requirements, 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.

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. Certain of our competitors may possess and employ financial, technical and personnel resources greater than ours.

Those companies may be able to pay more for productive crude oil and natural gas properties and exploratory prospects and to evaluate, bid for and purchase a greater number of properties and prospects than our financial or personnel resources permit. In addition, companies may be able to offer better compensation packages to attract and retain qualified personnel than we are able to offer. The cost to attract and retain qualified personnel has increased 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 financial condition and results of operations.

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.

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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 of December 31, 2011, non-operated properties represented 15% of our estimated proved developed reserves, 14% of our estimated proved undeveloped reserves, and 14% of our estimated total proved reserves. 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 required to fund 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 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; and
- 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 trustees 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 15, 2012, outstanding borrowings under our revolving credit facility were $900.0 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 $9.0 million and a $5.6 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.

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

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 ($378.8 million in receivables at December 31, 2011), our joint interest receivables ($398.8 million at December 31, 2011), and counterparty credit risk associated with our derivative instrument receivables ($10.3 million at December 31, 2011). 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, 2011 accounted for 41% of our total revenues. We generally do not require our customers to post collateral. Additionally, our use of derivative instruments involves the risk that our counterparties will be unable to meet their obligations under the arrangements. 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.

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

To achieve a more predictable cash flow and 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 *Part II, Item 7. Management s Discussion and Analysis of Financial Condition and Results of Operations Crude Oil and Natural Gas Hedging* and *Part II, 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 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 and our desire to stabilize cash flows necessary for the development of our undeveloped crude oil and natural gas reserves. As part of our risk management program, we have hedged a significant portion of our forecasted production through 2013. We utilize a combination of derivative contracts based on West Texas Intermediate (WTI) crude oil pricing, Inter-Continental Exchange pricing for Brent crude oil, and Henry Hub pricing for natural gas. We believe our derivative contracts provide relevant protection from price fluctuations in the U.S. markets where we deliver and sell our production. The pricing for Brent crude oil is believed to be a better reflection of the sales prices currently being realized in certain of our U.S. market centers. However, in the event Brent prices increase significantly, the prices realized in those U.S. market centers may no longer be reflective of Brent prices. In such a circumstance, we may incur significant realized cash losses upon settling our crude oil derivative instruments. Such losses may be incurred without seeing a corresponding increase in revenues from higher realized prices on our physical sales of crude oil.

Our Chairman and Chief Executive Officer owns approximately 68% of our outstanding common stock, giving him influence and control in corporate transactions and other matters, including a sale of our Company.

As of December 31, 2011, Harold G. Hamm, our Chairman and Chief Executive Officer, beneficially owned 123,159,048 shares of our outstanding common stock representing approximately 68% 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.

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

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We may be subject to risks as a result of cyber attacks targeting systems and infrastructure used by the oil and gas industry.

Computers control nearly all of the oil and gas production and distribution systems in the U.S. and abroad, some of which are utilized to transport our production to market. A cyber attack directed at oil and gas production and distribution systems could damage critical distribution and/or storage assets or the environment, delay or prevent delivery of production to markets and make it difficult or impossible to accurately account for production and settle transactions. The occurrence of such an attack against any of the aforementioned production and distribution systems could have a material adverse effect on our financial condition and results of operations.

Item 1B. Unresolved Staff Comments

There were no unresolved Securities and Exchange Commission staff comments at December 31, 2011.

Item 2. Properties

The information required by Item 2 is contained in *Part I, Item 1. Business Crude Oil and Natural Gas Operations*.

Item 3. Legal Proceedings

In November 2010, an alleged 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 crude oil and natural gas wells located in Oklahoma. The plaintiffs seek recovery of compensatory damages, interest, punitive damages and attorney fees on behalf of the alleged class. The Company has responded to the petition, denied the allegations and raised a number of affirmative defenses. Discovery has commenced and information and documents are being exchanged. The Company is not currently able to estimate what impact, if any, the action will have on its financial condition, results of operations or cash flows given the preliminary status of the matter and uncertainties with respect to, among other things, the nature of the claims and defenses, the potential size of the class, the scope and types of the properties and agreements involved, the production years involved, and the ultimate potential outcome of the matter.

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. Mine Safety Disclosures

Not applicable.

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Part II

Item 5. Market for Registrant s Common Equity, Related Stockholder 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 for each quarter of the previous two years. No cash dividends were declared during the previous two years.

	2011 Quarter Ended				2010 Quarter Ended			
	March 31	June 30	September 30	December 31	March 31	June 30	September 30	December 31
High	$ 73.48	$ 72.73	$ 71.77	$ 72.98	$ 46.18	$ 52.53	$ 48.65	$ 59.98
Low	56.55	57.89	46.25	42.43	36.27	39.35	38.23	45.00
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 15, 2012, the number of record holders of our common stock was 148. Management believes, after inquiry, that the number of beneficial owners of our common stock is approximately 48,500. On February 15, 2012, the last reported sales price of our Common Stock, as reported on the New York Stock Exchange, was $82.95 per share.

The following table summarizes our purchases of our common stock during the quarter ended December 31, 2011:

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, 2011 to October 31, 2011	39,413	$ 48.76		
November 1, 2011 to November 30, 2011	18,602	$ 66.26		
December 1, 2011 to December 31, 2011	1,499	$ 71.66		
Total	59,514	$ 54.81		

(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.

Equity Compensation Plan Information

The following table sets forth the information as of December 31, 2011 relating to equity compensation plans:

	Number of Shares to be Issued Upon	Weighted-Average Exercise Price of Outstanding Options	Remaining Shares Available for Future Issuance Under Equity

	Exercise of Outstanding Options (1)		Compensation Plans (2)
Equity Compensation Plans Approved by Shareholders	86,500	$ 0.71	2,631,287
Equity Compensation Plans Not Approved by Shareholders			

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(1) All shares to be issued pursuant to the exercise of outstanding options are issuable pursuant to the 2000 Plan.

(2) All remaining shares (2,631,287) are available for issuance under the 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.

Our peer group is comprised of Cabot Oil & Gas Corporation, Cimarex Energy Co., Concho Resources Inc., Denbury Resources Inc., Forest Oil Corporation, Newfield Exploration Company, Pioneer Natural Resources Company, Range Resources Corporation, Ultra Petroleum Corp., and Whiting Petroleum Corporation. We selected these companies because they are publicly traded exploration and production companies similar in size and operations to us.

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Item 6. Selected Financial Data

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

The following historical consolidated financial data, as it relates to each of the fiscal years ended December 31, 2007 through 2011, 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 *Part II, 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,				
	2011	2010	2009	2008	2007
Income Statement data					
(in thousands, except per share data)					
Crude oil and natural gas sales	$ 1,647,419	$ 948,524	$ 610,698	$ 939,906	$ 606,514
Loss on derivative instruments, net (1)	(30,049)	(130,762)	(1,520)	(7,966)	(44,869)
Total revenues	1,649,789	839,065	626,211	960,490	582,215
Income from continuing operations	429,072	168,255	71,338	320,950	28,580
Net Income	429,072	168,255	71,338	320,950	28,580
Basic earnings per share:					
From continuing operations	$ 2.42	$ 1.00	$ 0.42	$ 1.91	$ 0.17
Net income per share	$ 2.42	$ 1.00	$ 0.42	$ 1.91	$ 0.17
Shares used in basic earnings per share	177,590	168,985	168,559	168,087	164,059
Diluted earnings per share:					
From continuing operations	$ 2.41	$ 0.99	$ 0.42	$ 1.89	$ 0.17
Net income per share	$ 2.41	$ 0.99	$ 0.42	$ 1.89	$ 0.17
Shares used in diluted earnings per share	178,230	169,779	169,529	169,392	165,422
Pro forma C-corporation (2)					
Pro forma income from continuing operations					$ 184,002
Pro forma net income					184,002
Pro forma basic earnings per share					1.12
Pro forma diluted earnings per share					1.11
Production					
Crude oil (MBbl) (3)	16,469	11,820	10,022	9,147	8,699
Natural gas (MMcf)	36,671	23,943	21,606	17,151	11,534
Crude oil equivalents (MBoe)	22,581	15,811	13,623	12,006	10,621
Average sales prices (4)					
Crude oil ($/Bbl)	$ 88.51	$ 70.69	$ 54.44	$ 88.87	$ 63.55
Natural gas ($/Mcf)	5.24	4.49	3.22	6.90	5.87
Crude oil equivalents ($/Boe)	73.05	59.70	45.10	77.66	58.31
Average costs per Boe ($/Boe) (4)					
Production expenses	$ 6.13	$ 5.87	$ 6.89	$ 8.40	$ 7.35
Production taxes and other expenses	6.42	4.82	3.37	4.84	3.13
Depreciation, depletion, amortization and accretion	17.33	15.33	15.34	12.30	9.00
General and administrative expenses (5)	3.23	3.09	3.03	2.95	3.15
Proved reserves at December 31					
Crude oil (MBbl)	326,133	224,784	173,280	106,239	104,145
Natural gas (MMcf)	1,093,832	839,568	504,080	318,138	182,819
Crude oil equivalents (MBoe)	508,438	364,712	257,293	159,262	134,615
Other financial data (in thousands)					
Net cash provided by operations	$ 1,067,915	$ 653,167	$ 372,986	$ 719,915	$ 390,648
Net cash used in investing activities	(2,004,714)	(1,039,416)	(499,822)	(927,617)	(483,498)
Net cash provided by financing activities	982,427	379,943	135,829	204,170	94,568
EBITDAX (6)	1,303,959	810,877	450,648	757,708	469,885
Capital expenditures	2,224,096	1,237,189	433,991	988,593	525,677
Cash dividends per share	$	$	$	$	$ 0.33
Balance Sheet data at December 31 (in thousands)					
Total assets	$ 5,646,086	$ 3,591,785	$ 2,314,927	$ 2,215,879	$ 1,365,173
Long-term debt, including current maturities	1,254,301	925,991	523,524	376,400	165,000
Shareholders equity	2,308,126	1,208,155	1,030,279	948,708	623,132

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(1) Derivative instruments are not designated as hedges for accounting purposes 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 gains (losses) on derivative instruments of $4.1 million, ($166.2) million, ($2.1) million and ($26.7) million for the years ended December 31, 2011, 2010, 2009, and 2007, respectively. There were no unrealized gains or losses on derivative instruments for the year ended December 31, 2008.

(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. In connection with our initial public offering, we converted to a subchapter C corporation. Pro forma adjustments are reflected to provide for income taxes as if we had been a subchapter C corporation for the applicable period 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 the applicable pro forma period presented.

(3) At various times, we have stored crude oil due to pipeline line fill requirements, low commodity prices, or transportation constraints or we have sold crude oil from inventory. These actions result in differences between our produced and sold crude oil volumes. For the year 2011, crude oil sales volumes were 30 MBbls less than crude oil production 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 year 2007, crude oil sales volumes were 221 MBbls less than crude oil production volumes.

(4) Average sales prices and average costs per Boe have been computed using sales volumes and exclude any effect of derivative transactions.

(5) General and administrative expenses ($/Boe) include non-cash equity compensation expense of $0.73 per Boe, $0.74 per Boe, $0.84 per Boe, $0.75 per Boe and $1.23 per Boe for the years ended December 31, 2011, 2010, 2009, 2008 and 2007, respectively.

(6) 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. A reconciliation of net income to EBITDAX is provided in *Part II, 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 *Part I, 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 *Part I, 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, development 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 Anadarko Woodford and Arkoma Woodford plays in Oklahoma. The East region contains properties east of the Mississippi river including the Illinois Basin and the state of 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 provide the means 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 commodity 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 affect crude oil and natural gas prices. In addition, the prices we realize for our crude oil and natural gas production are affected by price differences in the markets where we deliver our production.

At December 31, 2011, our estimated proved reserves totaled 508.4 MMBoe, an increase of 39% over proved reserves of 364.7 MMBoe at December 31, 2010. The increase was primarily driven by successful drilling results in North Dakota Bakken and the Anadarko Woodford play of Oklahoma, coupled with higher crude oil prices in 2011. Extensions and discoveries in our key operating areas were partially offset by the removal of 24.2 MMBoe of proved undeveloped reserves primarily resulting from management s decision to defer drilling on certain dry gas properties in the Arkoma Woodford play in Oklahoma given the current and projected prices for natural gas.

The Bakken field comprised 58% of our proved reserves at December 31, 2011, with the Anadarko Woodford and Arkoma Woodford plays comprising 26% and the Red River units in North Dakota, South Dakota and Montana comprising 13%. Estimated proved developed reserves were 205.2 MMBoe at December 31, 2011, representing 40% of our total estimated proved reserves compared with 38% at year-end 2010. Crude oil comprised 64% of our 508.4 MMBoe of estimated proved reserves at December 31, 2011 compared to 62% at December 31, 2010.

We seek to operate wells in which we own an interest, and we operated wells that accounted for 86% of our PV-10 and 64% of our 3,255 gross wells as of December 31, 2011. 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, 2011, we added 367,668 MBoe of proved reserves through extensions and discoveries, compared to 2,462 MBoe added through acquisitions. During this three-year period, our production increased from 13,623 MBoe in 2009 to 22,581 MBoe in 2011. Proved reserve additions from all sources amounted to 166,307 MBoe for the year ended December 21, 2011, generating a reserve replacement rate of 736% for the year.

An aspect of our business strategy has been to acquire large undeveloped acreage positions in new or developing resource plays. As of December 31, 2011 we held 2,089,266 gross (1,229,425 net) undeveloped acres, including 604,009 net undeveloped acres in the Bakken field in Montana and North Dakota and 250,506 net undeveloped acres in the Oklahoma Woodford play. 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.

For the year ended December 31, 2011, our crude oil and natural gas production increased to 22,581 MBoe (61,865 Boe per day), up 6,770 MBoe, or 43%, from the year ended December 31, 2010. Crude oil accounted for 73% of our 2011 production. Crude oil and natural gas production was 6,920 MBoe for the fourth quarter of 2011, a 13% increase over production of 6,099 MBoe for the third quarter of 2011 and a 57% increase over production of 4,419 MBoe for the fourth quarter of 2010. The increase in 2011 production was primarily driven by an increase in production from our properties in the North Dakota Bakken field and the Anadarko Woodford play in Oklahoma due to the continued success of our drilling programs in those areas. Our Bakken production in North Dakota increased to 9,733 MBoe for the year ended December 31, 2011, a 90% increase over the comparable 2010 period. Fourth quarter 2011 production in the North Dakota Bakken field increased 99% over the fourth quarter of 2010. Our production in the Anadarko Woodford play totalled 2,171 MBoe for the year ended December 31, 2011, 367% higher than the same period in 2010. Anadarko Woodford production increased 476% in the fourth quarter of 2011 compared to the fourth quarter of 2010.

Our crude oil and natural gas revenues for the year ended December 31, 2011 increased 74% to $1,647.4 million due to a 22% increase in realized commodity prices along with a 42% increase in sales volumes compared to the same period in 2010. Our realized price per Boe increased $13.35 to $73.05 for the year ended December 31, 2011 compared to the year ended December 31, 2010. Crude oil accounted for 88% of our total 2011 crude oil and natural gas revenues compared to 89% for 2010.

The differential between NYMEX calendar month average crude oil prices and our realized crude oil price per barrel for the year ended December 31, 2011 was $6.39 compared to $9.02 for the year ended December 31, 2010. For the fourth quarter of 2011, the crude oil price differential was $5.00 per barrel, an improvement over a differential of $9.92 per barrel for the fourth quarter of 2010. A significant portion of our operated crude oil production in the North region is being sold in markets other than Cushing, Oklahoma and is priced, apart from transportation costs, at a premium to the West Texas Intermediate benchmark pricing in that market center, which has resulted in improved differentials.

Our cash flows from operating activities for the year ended December 31, 2011 were $1,067.9 million, an increase from $653.2 million provided by our operating activities during the comparable 2010 period. The increase in operating cash flows was primarily due to increased crude oil and natural gas revenues as a result of increased commodity prices and sales volumes, partially offset by an increase in realized losses on derivatives and higher production expenses, production taxes, general and administrative expenses and other expenses associated with the growth of our operations in 2011.

Our capital expenditures budget for 2011 was $2.0 billion, excluding property acquisitions which were not provided for in our budget. During the year ended December 31, 2011, we invested $2,046.1 million in our capital program (including increased accruals for capital expenditures of $173.6 million and $14.9 million of seismic costs and excluding unbudgeted property acquisitions). During 2011, we invested $178 million in unbudgeted leasehold and producing property acquisitions, resulting in total capital expenditures of $2,224.1 million for the year. Our 2011 capital program focused primarily on exploration and development activity in the Bakken field of North Dakota and Montana and the Anadarko Woodford play in Oklahoma.

In November 2011, our Board of Directors approved a 2012 capital expenditures budget of $1.75 billion. Our 2012 capital program will continue to focus on the Bakken and Anadarko Woodford plays. In 2012, we expect to participate as a buyer of properties when and if we have the ability to increase our position in strategic plays at favorable terms. Potential acquisition expenditures are not budgeted.

In January 2012 we requested, and were granted by the lenders, an increase in our credit facility s aggregate commitments from $750 million to $1.25 billion, effective January 31, 2012. Our borrowing base of $2.25 billion and all other substantive terms of the credit facility remained unchanged. The increased commitment level will provide additional available liquidity if needed to maintain our growth strategy, take advantage of business opportunities, and fund our capital program.

Due to the volatility of crude oil and natural gas prices and our desire to develop our substantial inventory of undeveloped reserves as part of our capital program, we have hedged a substantial portion of our forecasted production from our estimated proved reserves through 2013. We expect our cash flows from operations, our remaining cash balance, and the availability of our credit facility will be sufficient to meet our capital expenditure needs for the next 12 months.

How We Evaluate Our Operations

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

- volumes of crude oil and natural gas produced;
- crude oil and natural gas prices realized;
- per unit operating and administrative costs; and
- EBITDAX (a non-GAAP financial measure).

The following table contains financial and operating highlights for the periods presented.

	Year ended December 31, 2011	2010	2009
Average daily production:			
Crude oil (Bbl per day)	45,121	32,385	27,459
Natural gas (Mcf per day)	100,469	65,598	59,194
Crude oil equivalents (Boe per day)	61,865	43,318	37,324
Average sales prices: (1)			
Crude oil ($/Bbl)	$ 88.51	$ 70.69	$ 54.44
Natural gas ($/Mcf)	5.24	4.49	3.22
Crude oil equivalents ($/Boe)	73.05	59.70	45.10
Production expenses ($/Boe) (1)	6.13	5.87	6.89
General and administrative expenses ($/Boe) (1) (2)	3.23	3.09	3.03
Net income (in thousands)	429,072	168,255	71,338
Diluted net income per share	2.41	0.99	0.42
EBITDAX (in thousands) (3)	1,303,959	810,877	450,648

(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 $0.73 per Boe, $0.74 per Boe, and $0.84 per Boe for the years ended December 31, 2011, 2010 and 2009, 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 U.S. GAAP. A reconciliation of net income to EBITDAX is provided subsequently under the heading *Non-GAAP Financial Measures*.

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Results of Operations

The following table presents selected financial and operating information for each of the periods presented.

	Year Ended December 31,		
	2011	2010	2009
	Dollars in thousands, except sales price data		
Crude oil and natural gas sales	$ 1,647,419	$ 948,524	$ 610,698
Loss on derivative instruments, net [1]	(30,049)	(130,762)	(1,520)
Total revenues	1,649,789	839,065	626,211
Operating costs and expenses [2]	889,037	528,744	493,923
Other expenses, net	73,307	51,854	22,280
Income before income taxes	687,445	258,467	110,008
Provision for income taxes	258,373	90,212	38,670
Net income	$ 429,072	$ 168,255	$ 71,338
Production volumes:			
Crude oil (MBbl) [3]	16,469	11,820	10,022
Natural gas (MMcf)	36,671	23,943	21,606
Crude oil equivalents (MBoe)	22,581	15,811	13,623
Sales volumes:			
Crude oil (MBbl) [3]	16,439	11,898	9,940
Natural gas (MMcf)	36,671	23,943	21,606
Crude oil equivalents (MBoe)	22,551	15,889	13,541
Average sales prices: [4]			
Crude oil ($/Bbl)	$ 88.51	$ 70.69	$ 54.44
Natural gas ($/Mcf)	5.24	4.49	3.22
Crude oil equivalents ($/Boe)	73.05	59.70	45.10

(1) Amounts include an unrealized non-cash mark-to-market gain on derivative instruments of $4.1 million for the year ended December 31, 2011 and 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.

(2) Net of gain on sale of assets of $20.8 million, $29.6 million, and $0.7 million for the years ended December 31, 2011, 2010, and 2009, respectively. In March 2011, we assigned certain non-strategic leaseholds in the state of Michigan to a third party for cash proceeds of $22.0 million and recognized a pre-tax gain on the transaction of $15.3 million. In June 2010, we sold certain non-strategic leaseholds located in Louisiana to a third party for cash proceeds of $35.4 million and recognized a pre-tax gain on the transaction of $31.7 million. These transactions 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, low commodity prices, or transportation constraints or we have sold crude oil from inventory. These actions result in differences between produced and sold crude oil volumes. Crude oil sales volumes were 30 MBbls less than crude oil production for the year ended December 31, 2011, 78 MBbls more than crude oil production for the year ended December 31, 2010 and 82 MBbls less than crude oil production for the year ended December 31, 2009.

(4) Average sales prices have been calculated using sales volumes and exclude any effect of derivative transactions.

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Year ended December 31, 2011 compared to the year ended December 31, 2010

Production

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

	Year Ended December 31,					
	2011		2010		Volume	Percent
	Volume	Percent	Volume	Percent	increase	increase
Crude oil (MBbl)	16,469	73%	11,820	75%	4,649	39%
Natural Gas (MMcf)	36,671	27%	23,943	25%	12,728	53%
Total (MBoe)	22,581	100%	15,811	100%	6,770	43%

	Year Ended December 31,					
	2011		2010		Volume increase	Percent increase
	MBoe	Percent	MBoe	Percent	(decrease)	(decrease)
North Region	17,462	77%	12,431	79%	5,031	40%
South Region	4,705	21%	2,915	18%	1,790	61%
East Region	414	2%	465	3%	(51)	(11%)
Total	22,581	100%	15,811	100%	6,770	43%

Crude oil production volumes increased 39% during the year ended December 31, 2011 compared to the year ended December 31, 2010. Production increases in the Bakken field and the Anadarko Woodford play contributed incremental production volumes in 2011 of 4,410 MBbls, a 72% increase over production in these areas for the same period in 2010. Production growth in these areas is primarily due to increased drilling activity and higher well completions resulting from our accelerated drilling program for 2011. Additionally, production in the Cedar Hills field increased 203 MBbls, or 5%, in 2011 due to new wells being completed and enhanced recovery techniques being successfully applied.

Natural gas production volumes increased 12,728 MMcf, or 53%, during the year ended December 31, 2011 compared to the same period in 2010. Natural gas production in the North Dakota Bakken field was up 3,529 MMcf, or 88%, for the year ended December 31, 2011 compared to the same period in 2010 due to new wells being completed and gas from existing wells being connected to natural gas processing plants in North Dakota. We expect natural gas production growth in North Dakota Bakken to be further enhanced by the increased capacity of natural gas processing plants in the play, which will enable us to deliver more natural gas to market. Natural gas production in the Anadarko Woodford play increased 8,971 MMcf, or 366%, due to additional wells being completed and producing in the year ended December 31, 2011 compared to the same period in 2010. Further, natural gas production increased 502 MMcf in non-Woodford areas of our South region due to the completion of new wells during the period. These increases were partially offset by a 498 MMcf decrease in natural gas production from our Arkoma Woodford properties, which consist primarily of dry gas. In 2011, we scaled back our Arkoma Woodford drilling program due to the unfavorable pricing environment for natural gas, instead choosing to focus on the liquids-rich Anadarko Woodford play.

Revenues

Our total revenues are comprised of sales of crude oil and natural gas, realized and unrealized changes in the fair value of our derivative instruments and revenues associated with crude oil and natural gas service operations.

Crude Oil and Natural Gas Sales. Crude oil and natural gas sales for the year ended December 31, 2011 were $1,647.4 million, a 74% increase from sales of $948.5 million for the same period in 2010. Our sales volumes increased 6,662 MBoe, or 42%, over the same period in 2010 due to the continuing success of our drilling programs in the North Dakota Bakken field and Anadarko Woodford play. Our realized price per Boe increased $13.35 to $73.05 for the year ended December 31, 2011 from $59.70 for the year ended December 31, 2010. The differential between NYMEX calendar month average crude oil prices and our realized crude oil price per barrel for the year ended December 31, 2011 was $6.39 compared to $9.02 for the year ended December 31, 2010. A significant portion of our operated crude oil production in the North region is being sold in markets other than Cushing, Oklahoma and is priced, apart from transportation costs, at a premium to West Texas Intermediate benchmark pricing, which has resulted in improved differentials.

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 of derivative instruments in the consolidated statements of income under the caption Loss on derivative instruments, net , which is a component of total revenues.

During the year ended December 31, 2011, we realized losses on crude oil derivatives of $71.4 million and realized gains on natural gas derivatives of $37.3 million. During the year ended December 31, 2011, we reported an unrealized non-cash mark-to-market gain on crude oil derivatives of $18.8 million and an unrealized non-cash mark-to-market loss on natural gas derivatives of $14.7 million. During the year ended December 31, 2010, we realized gains on crude oil derivatives of $13.2 million and natural gas derivatives of $22.3 million. During the year ended December 31, 2010, we reported an unrealized non-cash mark-to-market loss on crude oil derivatives of $186.0 million and an unrealized non-cash mark-to-market gain on natural gas derivatives of $19.8 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	2011	2010	Variance
Average sales price ($/Bbl)	$ 92.30	$ 69.35	$ 22.95
Sales volumes (barrels)	259,000	227,000	32,000

The average sales price for reclaimed crude oil sold from our central treating units was $22.95 per barrel higher for the year ended December 31, 2011 than the comparable 2010 period. This contributed to an increase in reclaimed crude oil revenue of $7.0 million to $23.8 million and contributed to an overall increase in crude oil and natural gas service operations revenue of $11.1 million for the year ended December 31, 2011. Also contributing to the increase in crude oil and natural gas service operations revenue was a $3.3 million increase in saltwater disposal income resulting from increased activity. Associated crude oil and natural gas service operations expenses increased $8.6 million to $26.7 million during the year ended December 31, 2011 from $18.1 million during the year ended December 31, 2010 due mainly to an increase in the costs of purchasing and treating reclaimed crude oil for resale and in providing saltwater disposal services.

Operating Costs and Expenses

Production Expenses and Production Taxes and Other Expenses. Production expenses increased 48% to $138.2 million during the year ended December 31, 2011 from $93.2 million during the year ended December 31, 2010. This increase is primarily the result of higher production volumes from an increase in the number of producing wells. Production expenses per Boe increased to $6.13 for the year ended December 31, 2011 from $5.87 per Boe for the year ended December 31, 2010. Contributing to the per-unit increase were increases in well site and road maintenance costs and saltwater disposal costs in the 2011 second quarter, all resulting from abnormal rainfall and flooding in North Dakota in April and May 2011. Also contributing to the per-unit increase were higher workover expenditures from increased activity as well as general inflationary pressure on the costs of oilfield services and equipment.

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Production taxes and other expenses increased $68.2 million, or 89%, to $144.8 million during the year ended December 31, 2011 compared to the year ended December 31, 2010 as a result of higher crude oil and natural gas revenues resulting from increased commodity prices and sales volumes along with the expiration of various tax incentives. Production taxes and other expenses include charges for marketing, gathering, dehydration and compression fees primarily related to natural gas sales in the Oklahoma Woodford and North Dakota Bakken areas of $13.7 million and $6.1 million for the year ended December 31, 2011 and 2010, respectively. The increase in other charges is primarily due to the significant increase in natural gas sales volumes in 2011. Production taxes, excluding other charges, as a percentage of crude oil and natural gas revenues were 7.9% for the year ended December 31, 2011 compared to 7.5% for the year ended December 31, 2010. 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 generally 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 reverts to the statutory rate. Our overall production tax rate is expected to further increase as we continue to expand our operations in North Dakota and as production tax incentives we currently receive for horizontal wells reach the end of their incentive periods.

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

	Year Ended December 31,	
$/Boe	2011	2010
Production expenses	$ 6.13	$ 5.87
Production taxes and other expenses	6.42	4.82
Production expenses, production taxes and other expenses	$ 12.55	$ 10.69

Exploration Expenses. Exploration expenses consist primarily of dry hole costs and exploratory geological and geophysical costs that are expensed as incurred. The following table shows the components of exploration expenses for the periods indicated.

	Year Ended December 31,	
(in thousands)	2011	2010
Geological and geophysical costs	$ 19,971	$ 9,739
Dry hole costs	7,949	3,024
Exploration expenses	$ 27,920	$ 12,763

Geological and geophysical costs increased $10.2 million for the year ended December 31, 2011 due to an increase in acquisitions of seismic data in connection with our increased capital budget for 2011. Dry hole costs increased $4.9 million in 2011 resulting from increased drilling activity. Dry hole costs in 2011 were mainly concentrated in Arkoma Woodford and Michigan.

Depreciation, Depletion, Amortization and Accretion. Total DD&A increased $147.3 million, or 60%, in the year ended December 31, 2011 compared to the year ended December 31, 2010 primarily due to a 43% increase in production volumes. The following table shows the components of our DD&A on a unit of sales basis.

	Year Ended December 31,	
$/Boe	2011	2010
Crude oil and natural gas production	$ 16.90	$ 14.92
Other equipment	0.29	0.24
Asset retirement obligation accretion	0.14	0.17
Depreciation, depletion, amortization and accretion	$ 17.33	$ 15.33

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The increase in DD&A per Boe is partially the result of a gradual shift in our production from our historic base of the Red River units in the Cedar Hills field to newer production bases in the Bakken and Oklahoma Woodford plays. The producing properties in our newer areas typically carry higher DD&A rates due to the higher cost of developing reserves in those areas compared to our older, more mature properties.

Property Impairments. Property impairments increased in the year ended December 31, 2011 by $43.5 million to $108.5 million compared to $65.0 million for the year ended December 31, 2010.

Non-producing properties consist of undeveloped leasehold costs and costs associated with the purchase of certain proved undeveloped reserves. Individually insignificant non-producing properties are amortized on an aggregate basis based on our estimated experience of successful drilling and the average holding period. Impairments of non-producing properties increased $29.1 million for the year ended December 31, 2011 to $92.4 million compared to $63.3 million for the year ended December 31, 2010. The increase resulted from a larger base of amortizable costs in 2011 coupled with changes in management s estimates of the undeveloped properties no longer expected to be developed before lease expiration. Given current and projected prices for natural gas, we have elected to defer drilling on certain dry gas properties, thereby resulting in higher amortization of costs in 2011. We currently have no individually significant non-producing properties that would be assessed for impairment on a property-by-property basis.

Impairment provisions for proved crude oil and natural gas properties were $16.1 million for the year ended December 31, 2011 compared to $1.7 million for the same period in 2010. We evaluate 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 2011 primarily reflect uneconomic operating results for initial wells drilled on our acreage in the Niobrara play in Colorado. Exploration and development of the Niobrara play using multi-stage fracture stimulation technology is in the very early stages and results to date have been varied. We are seeking ways to refine and improve our geologic model and completion techniques for the play and have been encouraged by improved production being seen on our newest completions in the play. Impairments in 2010 reflect uneconomic operating results in the East region and a non-Bakken Montana field in the North region.

General and Administrative Expenses. General and administrative (G&A) expenses increased $23.7 million to $72.8 million for the year ended December 31, 2011 from $49.1 million for the comparable period in 2010. G&A expenses include non-cash charges for equity compensation of $16.6 million and $11.7 million for the years ended December 31, 2011 and 2010, respectively. The increase in equity compensation in 2011 resulted from larger grants of restricted stock due to employee growth along with an increase in our grant-date stock prices during the year which increased expense recognition. G&A expenses excluding equity compensation increased $18.8 million for the year ended December 31, 2011 compared to the same period in 2010. The increase was primarily related to an increase in personnel costs and office-related expenses associated with our rapid growth. Over the past year, we have grown from 493 total employees in December 2010 to 609 total employees in December 2011, a 24% increase. In March 2011, we announced plans to relocate our corporate headquarters from Enid, Oklahoma to Oklahoma City, Oklahoma. The move is a key element of our growth strategy of tripling our production and proved reserves between 2009 and 2014 and is expected to be completed during 2012. For the year ended December 31, 2011, we have recognized approximately $3.2 million of costs in G&A expenses associated with the relocation. We currently expect to incur a total of approximately $15 million to $25 million of costs in conjunction with the relocation, with the majority of such costs expected to be incurred in the second and third quarters of 2012.

The following table shows the components of G&A expenses on a unit of sales basis.

	Year Ended December 31,	
$/Boe	2011	2010
General and administrative expenses	$ 2.36	$ 2.35
Non-cash equity compensation	0.73	0.74
Corporate relocation expenses	0.14	
General and administrative expenses	$ 3.23	$ 3.09

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Interest Expense. Interest expense increased $23.6 million, or 44%, for the year ended December 31, 2011 compared to the same period in 2010 due to increases in our weighted average outstanding long-term debt balance and our weighted average interest rate. Our weighted average interest rate for the year ended December 31, 2011 was 7.2% with a weighted average outstanding long-term debt balance of $970.0 million compared to a weighted average interest rate of 7.0% with a weighted average outstanding long-term debt balance of $685.8 million for the same period in 2010. We issued $200 million of 7 3/8% Senior Notes in April 2010 and $400 million of 7 1/8% Senior Notes in September 2010, the net proceeds of which were used to repay credit facility borrowings that carried lower interest rates.

Our weighted average outstanding credit facility balance decreased to $70.0 million for the year ended December 31, 2011 compared to $121.7 million for the year ended December 31, 2010. The weighted average interest rate on our credit facility borrowings was 2.4% for the year ended December 31, 2011 compared to 2.7% for the same period in 2010. At December 31, 2011, we had $358.0 million of outstanding borrowings on our credit facility at a weighted average interest rate of 2.0%.

Income Taxes. We recorded income tax expense for the year ended December 31, 2011 of $258.4 million compared to $90.2 million for the year ended December 31, 2010. We provide for income taxes at a combined federal and state tax rate of approximately 38% after taking into account permanent taxable differences. See *Notes to Consolidated Financial Statements Note 8. Income Taxes* for more information.

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	Percent	increase	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,				Volume	Percent
	2010		2009		increase	increase
	MBoe	Percent	MBoe	Percent	(decrease)	(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 were 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.

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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.

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 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, the average sales price for reclaimed crude oil sold from our central treating units was $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 2009, 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

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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.

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 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 reverts to the statutory rate. 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.

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

	Year Ended December 31,	
$/Boe	2010	2009
Production expenses	$ 5.87	$ 6.89
Production taxes and other expenses	4.82	3.37
Production expenses, production taxes and other expenses	$ 10.69	$ 10.26

Exploration Expenses. Exploration expenses consist 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. 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.

	Year Ended December 31,	
$/Boe	2010	2009
Crude oil and natural gas production	$ 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, 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 our growth 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 2010 as compared to lower interest rates on our credit facility borrowings in 2009. 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 7.0% with a weighted average outstanding long-term debt balance of $685.8 million compared to a weighted average interest rate of 3.8% 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 2.7% for the year ended December 31, 2010 compared to 2.9% 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.

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 debt and equity securities. During the year ended December 31, 2011, our average realized sales price was $13.35 per Boe higher compared to the year ended December 31, 2010. The increase in realized commodity prices, coupled with our 42% increase in sales volumes in 2011 compared to 2010, resulted in improved cash flows from operations and better liquidity.

At December 31, 2011, we had $53.5 million of cash and cash equivalents and $389.2 million of available capacity under our revolving credit facility after considering outstanding letters of credit. Subsequent to December 31, 2011, we requested, and were granted by the lenders, an increase in our credit facility s aggregate commitments from $750 million to $1.25 billion, effective January 31, 2012. At February 15, 2012, we had $347.2 million of borrowing availability on our credit facility after considering the increased commitments and outstanding borrowings and letters of credit. The decrease in borrowing availability subsequent to December 31, 2011 resulted from borrowings incurred to fund our 2012 capital program and a February 2012 acquisition of producing and non-producing properties in North Dakota for $276 million.

Cash Flows

Cash Flows from Operating Activities

Our net cash provided by operating activities was $1,067.9 million and $653.2 million for the years ended December 31, 2011 and 2010, respectively. The increase in operating cash flows was primarily due to higher crude oil and natural gas revenues as a result of higher commodity prices and sales volumes, partially offset by an increase in realized losses on derivatives and increases in production expenses, production taxes, general and administrative expenses and other expenses associated with the growth of our operations in 2011.

Cash Flows used in Investing Activities

During the years ended December 31, 2011 and 2010, we had cash flows used in investing activities (excluding asset sales) of $2,035.6 million and $1,083.4 million, respectively, related to our capital program, inclusive of dry hole costs. The increase in cash flows used in investing activities in 2011 was primarily due to the continued acceleration of our drilling program, primarily in the North Dakota Bakken field and the Anadarko Woodford play in Oklahoma.

Cash Flows from Financing Activities

Net cash provided by financing activities for the year ended December 31, 2011 was $982.4 million and was primarily the result of the issuance and sale of an aggregate 10,080,000 shares of our common stock in March 2011 for total net proceeds of $659.4 million, after deducting underwriting discounts and offering-related expenses, coupled with net borrowings of $328 million on our credit facility to fund a portion of our 2011 capital program. Net cash provided by financing activities of $379.9 million for the year ended December 31, 2010 was mainly the result of receiving $587.2 million of net proceeds from the issuance of the 2020 Notes in April 2010 and the 2021 Notes in September 2010, reduced by net repayments of $196 million on our credit facility and $9.1 million of costs incurred in connection with our senior note issuances.

Future Sources of Financing

Although we cannot provide any assurance, assuming continued strength in crude oil prices and successful implementation of our business strategy, we believe funds from operating cash flows, our remaining cash balance, 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, budgeted capital expenditures, and commitments and contingencies for the next 12 months.

Based on our planned production growth and derivative contracts we have in place to limit the downside risk of adverse price movements associated with the forecasted sale of future production, we currently anticipate we will be able to generate or obtain funds sufficient to meet our short-term and long-term cash requirements. We intend to finance future capital expenditures primarily through cash flows from operations and through borrowings under our revolving credit facility, but we may also issue debt or equity securities or sell assets. The issuance of additional debt requires 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.

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Revolving Credit Facility

We have a revolving credit facility which had aggregate lender commitments totaling $750.0 million and a borrowing base of $2.25 billion at December 31, 2011, subject to semi-annual redetermination. The most recent borrowing base redetermination was completed in October 2011, whereby the lenders approved an increase in the borrowing base from $2.0 billion to $2.25 billion. Subsequent to December 31, 2011, we requested, and were granted by the lenders, an increase in the aggregate credit facility commitments from $750 million to $1.25 billion, effective January 31, 2012. Our borrowing base of $2.25 billion and all other substantive terms of the credit facility remained unchanged. The increased commitment level will provide additional available liquidity if needed to maintain our growth strategy, take advantage of business opportunities, and fund our capital program. The aggregate commitment level may be further increased at our option from time to time (provided no default exists) up to the lesser of $2.5 billion or the borrowing base then in effect. Borrowings under the facility bear interest, payable quarterly, at a rate per annum equal to the London Interbank Offered Rate (LIBOR) for one, two, three or six months, as elected by us, plus a margin ranging from 175 to 275 basis points, depending on the percentage of the borrowing base utilized, or the lead bank s reference rate (prime) plus a margin ranging from 75 to 175 basis points.

The commitments under our credit facility, which matures on July 1, 2015, are from a syndicate of 15 banks and financial institutions. We believe each member of the current syndicate 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 $1.25 billion commitment.

We had $358.0 million of outstanding borrowings and $389.2 million of borrowing availability (after considering outstanding letters of credit) on our credit facility as of December 31, 2011. As of February 15, 2012, we had $900.0 million of outstanding borrowings and $347.2 million of borrowing availability on our credit facility after considering the increased commitments and outstanding letters of credit. The increase in borrowings subsequent to December 31, 2011 resulted from borrowings incurred to fund our 2012 capital program and a February 2012 acquisition of producing and non-producing properties in North Dakota for $276 million.

Our 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 U.S. GAAP. A reconciliation of net income to EBITDAX is provided subsequently under the caption *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, 2011 and expect to maintain compliance for at least the next 12 months. At December 31, 2011, our current ratio, as defined, was 1.3 to 1.0 and our total funded debt to EBITDAX ratio was 1.0 to 1.0. We do not believe the restrictive covenants are reasonably likely to limit our ability to undertake additional debt or equity financing to a material extent.

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 2012. 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.

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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.

Derivative Activities

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 adequate funds are 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 and our desire to have the cash flows needed to fund the development of our inventory of undeveloped crude oil and natural gas reserves in conjunction with our growth strategy. While the use of hedging arrangements limits the downside risk of adverse price movements, their use also limits future revenues from upward price movements.

Our hedging transactions existing at December 31, 2011 are settled based upon reported settlement prices on the NYMEX, with our crude oil derivatives being tied to West Texas Intermediate (WTI) pricing and our natural gas derivatives being tied to Henry Hub pricing. A significant portion of our operated crude oil production in the North region is being sold in markets other than Cushing, Oklahoma and is priced, apart from transportation costs, at a premium to the WTI benchmark pricing in that market center. As such, WTI has become an unreliable reflection of the realized value of our North region crude oil production. Historically, WTI and Inter-Continental Exchange pricing for Brent crude oil have fluctuated together, but in 2011 the two indices began to diverge. At this time, we believe the current pricing for Brent crude oil is more reflective of the sales prices currently being realized for our North region production. Accordingly, for recent crude oil derivative contracts entered into subsequent to December 31, 2011, we decided to base such contracts on Brent pricing. While this approach is consistent with our current viewpoint, such viewpoint could change based on future fluctuations in WTI and Brent prices and the correlation of such prices to our realized prices. Therefore, our future hedging program may include contracts based on WTI prices, Brent prices, or a combination of both. A summary of Brent-based crude oil derivatives entered into after December 31, 2011 is provided subsequently under the heading *Crude Oil and Natural Gas Hedging.* Also refer to *Note 5. Derivative Instruments* in *Notes to Consolidated Financial Statements* for further discussion of the accounting applicable to our derivative instruments, a summary of open contracts at December 31, 2011 and the estimated fair value of those contracts as of that date. We have hedged a significant portion of our forecasted production through 2013. For a discussion of the potential risks associated with our hedging program, refer to *Part I, Item 1A. Risk Factors Our derivative activities could result in financial losses or reduce our earnings.*

Future Capital Requirements

Capital Expenditures

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

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During the year ended December 31, 2011, we participated in the completion of 563 gross (198.9 net) wells and invested $2,046.1 million in our capital program (including increases in accruals for capital expenditures of $173.6 million and $14.9 million of seismic costs and excluding unbudgeted property acquisitions). During 2011, we invested $178 million in unbudgeted leasehold and producing property acquisitions, resulting in total capital expenditures of $2,224.1 million for the year. Our 2011 capital expenditures were allocated as follows:

	Amount *in millions*
Exploration and development drilling	$ 1,774.3
Land costs	273.6
Capital facilities, workovers and re-completions	51.3
Buildings, vehicles, computers and other equipment	44.7
Acquisitions of producing properties	65.3
Seismic	14.9
Total	$ 2,224.1

Our 2011 capital program focused primarily on increased development in the North Dakota Bakken field and the Anadarko Woodford play in western Oklahoma.

In November 2011, our Board of Directors approved a 2012 capital expenditures budget of $1.75 billion. Our 2012 planned capital expenditures are expected to be allocated as follows:

	Amount *in millions*
Exploration and development drilling	$ 1,539
Land costs	94
Capital facilities, workovers and re-completions	90
Buildings, vehicles, computers and other equipment	7
Seismic	20
Total	$ 1,750

The 2012 capital plan will focus primarily on increased development in the North Dakota Bakken field and Anadarko Woodford play. During 2012, we expect to participate as a buyer of properties when and if we have the ability to increase our position in strategic plays at favorable terms. In February 2012, we acquired certain producing and non-producing properties in North Dakota for approximately $276 million. This transaction is not included in our 2012 capital budget reflected in the table above.

Although we cannot provide any assurance, assuming continued strength in crude oil prices and successful implementation of our business strategy, including the future development of our proved reserves and realization of our cash flows as anticipated, we believe funds from operating cash flows, our remaining cash balance, and our revolving credit facility will be sufficient to fund our 2012 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, changes in commodity prices, and regulatory, technological and competitive developments.

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Contractual Obligations

We have the following contractual obligations and commitments as of December 31, 2011:

		Payments due by period			
(in thousands)	Total	Less than 1 year (2012)	1 - 3 years (2013-2014)	3 - 5 years (2015-2016)	More than 5 years
Arising from arrangements on the balance sheet:					
Revolving credit facility	$ 358,000	$	$	$ 358,000	$
Senior Notes (1)	900,000				900,000
Interest expense (2)	610,695	75,545	150,678	139,846	244,626
Asset retirement obligations (3)	62,625	2,287	10,453	2,055	47,830
Arising from arrangements not on balance sheet:					
Operating leases (4)	5,901	2,191	3,340	176	194
Drilling rig commitments (5)	136,516	117,649	18,867		
Fracturing and well stimulation services (6)	43,738	27,050	16,688		
Firm transportation commitment (7)	30,988	6,771	13,505	10,712	
Total contractual obligations	$ 2,148,463	$ 231,493	$ 213,531	$ 510,789	$ 1,192,650

(1) Amounts represent scheduled maturities of our debt obligations at December 31, 2011 and do not reflect the discounts at which the Senior 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 credit facility borrowings outstanding at December 31, 2011 and assumes the weighted average interest rate on our credit facility borrowings of 2.0% at December 31, 2011 continues for the life of the 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 primarily represent leases for office space, office equipment, and hydraulic fracturing tank rentals. See *Notes to Consolidated Financial Statements Note 9. Lease Commitments.*

(5) We have drilling rig contracts with various terms extending through August 2014. 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) We have 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 October 2010, with two one-year extensions available to us at our discretion. Pursuant to the take-or-pay provisions, 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 the services are provided. Future commitments remaining as of December 31, 2011 amount to approximately $39 million, of which $22 million is expected to be incurred in 2012 and $17 million in 2013. Additionally, we have an agreement whereby a third party will provide coiled tubing well stimulation services for certain of our properties in Oklahoma at a fixed rate per month for calendar year 2012, resulting in total future commitments of approximately $5 million as of December 31, 2011. The commitments under these arrangements are not recorded in the accompanying consolidated balance sheets.

(7) We have a five-year firm transportation commitment, beginning in August 2011, to guarantee capacity totaling 10,000 barrels of crude oil per day on a major pipeline in order to reduce the impact of possible production curtailments that may arise due to limited transportation capacity. The transportation commitment is for crude oil production in the Bakken field where we allocate a significant portion of our capital expenditures. The commitment requires us to pay transportation reservation charges of $1.85 per barrel, or $6.8 million annually through August 2016, regardless of the amount of pipeline capacity used. The commitments under this agreement are not recorded in the accompanying consolidated balance sheets.

The Company is not committed under existing contracts to deliver fixed and determinable quantities of crude oil or natural gas in the future.

Corporate Relocation

In March 2011, we announced plans to relocate our corporate headquarters from Enid, Oklahoma to Oklahoma City, Oklahoma. The relocation is expected to provide more convenient access to our operations across the country, to our business partners and to an expanded pool of technical talent. The relocation is expected to be completed during 2012. We currently estimate we may incur a total of approximately $15 million to $25 million of costs in conjunction with our relocation, with the majority of such costs expected to be incurred in the second and third quarters of 2012. We generally expect to recognize the majority of relocation costs in our financial statements when incurred. As of December 31, 2011, we have recognized approximately $3.2 million of costs associated with our relocation efforts, which are included in the caption General and administrative expenses in the consolidated statements of income.

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 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 and our desire to have the cash flows needed to fund the development of our inventory of undeveloped crude oil and natural gas reserves in conjunction with our growth strategy.

While the use of hedging arrangements limits the downside risk of adverse price movements, their use also limits future revenues from upward 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.

Our hedging transactions existing at December 31, 2011 are settled based upon reported settlement prices on the NYMEX, with our crude oil derivatives being tied to West Texas Intermediate (WTI) pricing and our natural gas derivatives being tied to Henry Hub pricing. A significant portion of our operated crude oil production in the North region is being sold in markets other than Cushing, Oklahoma and is priced, apart from transportation costs, at a premium to the WTI benchmark pricing in that market center. As such, WTI has become an unreliable reflection of the realized value of our North region crude oil production. Historically, WTI and Inter-Continental Exchange pricing for Brent crude oil have fluctuated together, but in 2011 the two indices began to diverge. At this time, we believe the current pricing for Brent crude oil is more reflective of the sales prices currently being realized for our North region production. Accordingly, for recent crude oil derivative contracts entered into subsequent to December 31, 2011, we decided to base such contracts on Brent pricing. While this approach is consistent with our current viewpoint, such viewpoint could change based on future fluctuations in WTI and Brent prices and the correlation of such prices to our realized prices. Therefore, our future hedging program may include contracts based on WTI prices, Brent prices, or a combination of both.

Please see *Notes to Consolidated Financial Statements Note 5. Derivative Instruments* for further discussion of the accounting applicable to our derivative instruments, a summary of open contracts as of December 31, 2011 and the estimated fair value of those contracts as of that date.

Between January 1, 2012 and February 15, 2012, we entered into additional derivative contracts summarized in the tables below. None of these contracts have been designated for hedge accounting.

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Crude Oil

Period and Type of Contract	Bbls	Weighted Average Price
February 2012 - December 2012		
Swaps - ICE Brent Crude	3,591,500	$ 111.12
January 2013 - December 2013		
Swaps - ICE Brent Crude	1,460,000	$ 107.63

Natural Gas

Period and Type of Contract	MMBtus	Weighted Average Price
February 2012 - June 2012		
Swaps - Henry Hub	1,510,000	$ 3.06
July 2012 - December 2012		
Swaps - Henry Hub	3,680,000	$ 3.10
January 2013 - December 2013		
Swaps - Henry Hub	7,300,000	$ 3.73

Critical Accounting Policies and Estimates

Our historical consolidated financial statements and related footnotes 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 existing rules must be done and judgments must be made on how the specifics of a given rule apply to us.

In management s opinion, the most 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 crude oil and natural gas activities and derivatives, impairment of assets and income taxes. Management s judgments and estimates in these areas are based on information available from both internal and external sources, including engineers, geologists and historical experience in similar matters. Actual results could differ from the estimates as additional information becomes known.

Crude Oil and Natural Gas Reserves Estimation 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, 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 renewal is reasonably certain. 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 take into account recent production levels and other technical information about each of our fields. 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, changes in costs, 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 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 may result in material impairments of assets.

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 revenues and actual amounts are recorded in the month payment is received and are reflected in our consolidated statements of income as crude oil and natural gas sales. These variances have historically not been material.

Successful Efforts Method of Accounting

We use the successful efforts method of accounting for our crude oil and natural gas properties, whereby we capitalize 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. Geological and geophysical costs, seismic costs, lease rentals and costs associated with unsuccessful exploratory wells or 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 3 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.

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 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 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 industry-standard models that consider various inputs including quoted forward prices for commodities, time value, volatility factors, and 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 and interest rates. We validate our derivative valuations through management reviews and by comparison to our counterparties valuations for reasonableness.

Impairment of Assets

All of our long-lived assets are monitored for potential impairment when circumstances indicate 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 those 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, anticipated drilling programs, 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, 2011, we believe all 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 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 tax-paying companies. Our effective tax rate is affected by changes in the allocation of property, payroll, and revenues between states in which we own property as rates vary from state to state. 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 *Part II, Item 7. Management s Discussion and Analysis of Financial Condition and Results of Operations Contractual Obligations.*

Recent Accounting Pronouncements Not Yet Adopted

In May 2011, the Financial Accounting Standards Board (FASB) issued Accounting Standards Update (ASU) No. 2011-04, *Fair Value Measurement (Topic 820) Amendments to Achieve Common Fair Value Measurement and Disclosure Requirements in U.S. GAAP and IFRSs.* The amendments in ASU No. 2011-04 are the result of work by the FASB and the International Accounting Standards Board (IASB) to develop common global requirements for measuring fair value and for disclosing information about fair value measurements to improve the comparability of financial statements prepared in accordance with U.S. GAAP and IFRS. Many of the amendments in ASU No. 2011-04 offer clarification to existing guidance and are not intended to result in significant changes in the application of the fair value measurement guidance of U.S. GAAP. The new standard is effective for the first interim or annual reporting period beginning after December 15, 2011 and is required to be applied prospectively. We will adopt the requirements of ASU No. 2011-04 on January 1, 2012, which may require additional footnote disclosures for our derivative instruments and is not expected to have a material effect on our financial position, results of operations or cash flows.

In December 2011, the FASB issued ASU No. 2011-11, *Balance Sheet (Topic 210) Disclosures about Offsetting Assets and Liabilities*. The new standard requires an entity to disclose information about offsetting arrangements to enable financial statement users to understand the effect of netting arrangements on an entity s financial position. The disclosures are required for recognized financial instruments and derivative instruments that are subject to offsetting under current accounting literature or are subject to master netting arrangements irrespective of whether they are offset. The objective of the new disclosures is to facilitate comparison between entities that prepare financial statements on the basis of U.S. GAAP and entities that prepare financial statements under IFRS. The disclosure requirements will be effective for periods beginning on or after January 1, 2013 and must be applied retrospectively to all periods presented on the balance sheet. We will adopt the requirements of ASU No. 2011-11 on January 1, 2013, which may require additional footnote disclosures for our derivative instruments and is not expected to have a material effect on our financial position, results of operations or cash flows.

We are monitoring the joint standard-setting efforts of the FASB and IASB. There are a number of pending accounting standards being targeted for completion in 2012 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 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. In July 2010, the Dodd-Frank Act was enacted into law. This financial reform legislation includes provisions that require over-the-counter derivative transactions to be executed through an exchange or centrally cleared. The Dodd-Frank Act requires the CFTC, the SEC, and other regulators to establish rules and regulations to implement the new legislation. The CFTC has issued final regulations to implement significant aspects of the legislation, including new rules for the registration of swap dealers and major swap participants, requirements for reporting and recordkeeping, rules on customer protection in the context of cleared swaps, and position limits for swaps and other transactions based on the price of certain reference contracts, some of which are referenced in our swap contracts. Key regulations not yet finalized include those clarifying the definitions of swap dealer, major swap participant and swap and those establishing margin requirements for uncleared swaps and various trade execution and trade documentation requirements. These regulations may require or cause our counterparties to collect margin from us and may require us to clear our transactions or execute them on a derivatives contract market or swap execution facility, although the application of these provisions to us is uncertain at this time. The ultimate effect of the proposed new rules and any additional regulations on our business is uncertain. Of particular concern to us is whether the provisions of the final rules and regulations will allow us to qualify as a non-financial, commercial end user that is exempt from the requirement to clear our derivative contracts, and whether our status will allow our derivative counterparties to not require us to post margin in connection with our commodity price risk management activities. The remaining final rules and regulations on major provisions of the legislation, such as new margin requirements, are to be established through regulatory rulemaking. Although we cannot predict the ultimate outcome of these rulemakings, new rules and regulations in this area, 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 manage our financial and commercial risks related to fluctuations in commodity prices, increased regulatory reporting and recordkeeping, and market dislocations or disruptions, among other consequences, 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 rules that would require certain registrants to disclose payments they make to the U.S. Federal Government or foreign governments related to the commercial development of crude oil and natural gas. The proposed rules related to government payments are not yet finalized and the application of such rules to us is uncertain.

Climate change. Federal, state and local laws and regulations are increasingly being enacted to address concerns about the effects the emission of carbon dioxide and other identified greenhouse gases may have on the environment and climate worldwide. These effects are widely referred to as climate change. Since its December 2009 endangerment finding regarding the emission of carbon dioxide, methane and other greenhouse gases, the EPA has begun regulating sources of greenhouse gas emissions under the federal Clean Air Act. Among several regulations requiring reporting or permitting for greenhouse gas sources, the EPA finalized its tailoring rule in May 2010 that determines which stationary sources of greenhouse gases 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 November 2010, the EPA also finalized its greenhouse gas reporting requirements, beginning in March 2012, for certain oil and gas production facilities that emit 25,000 metric tons or more of carbon dioxide equivalent per year. We currently estimate our producing wells in five basins will be subject to the reporting requirements.

Moreover, in recent past the U.S. Congress has considered establishing a cap-and-trade program to reduce U.S. emissions of greenhouse gases, including carbon dioxide and methane. Under past 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 ever adopted, would be to impose increasing costs on the combustion of carbon-based fuels such as crude oil, refined petroleum products, and natural gas. In addition, while the prospect for such cap-and-trade legislation by the U.S. Congress remains uncertain, several states, including states in which we operate, have adopted, or are in the process of adopting, similar cap-and-trade programs.

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 we sell, emits carbon dioxide and other greenhouse gases. Thus, any current or future federal, state or local climate change initiatives could adversely affect demand for the crude oil and natural gas we produce by stimulating demand for alternative forms of energy that do not rely on the combustion of fossil fuels, and therefore could have a material adverse effect on our business. Although our compliance with any greenhouse gas regulations may result in increased compliance and operating costs, we do not expect the compliance costs for currently applicable regulations to be material. Moreover, while it is not possible at this time to estimate the compliance costs or operational impacts for any new legislative or regulatory developments in this area, we do not anticipate being impacted to any greater degree than other similarly situated competitors.

Hydraulic fracturing. Some activists have attempted to link hydraulic fracturing to various environmental problems, including adverse effects to drinking water supplies and migration of methane and other hydrocarbons. As a result, several federal agencies are studying the environmental risks with respect to hydraulic fracturing or evaluating whether to restrict its use. From time to time, legislation has been introduced in the U.S. Congress to amend the federal Safe Drinking Water Act to eliminate an existing exemption for hydraulic fracturing activities from the definition of underground injection, thereby requiring the crude oil and natural gas industry to obtain permits for hydraulic fracturing and to require disclosure of the additives used in the process. If ever adopted, such legislation could establish an additional level of regulation and permitting at the federal level. Scrutiny of hydraulic fracturing activities continues in other ways, with the EPA having commenced a multi-year study of the potential environmental impacts of hydraulic fracturing, the initial results of which are anticipated to be available by late 2012. The U.S. Department of the Interior has announced it will publish rules requiring companies to disclose the make-up of all materials used in hydraulic fracturing fluids on federal lands. The announced legislation will also require disclosure of the source, access route and transport of all water anticipated to be used in connection with hydraulic fracturing operations. The announced rules have not been published and we are not able to determine the extent of their impact on our operations on federal land. In addition to these federal initiatives, several state and local governments, including states in which we operate, have moved to require disclosure of fracturing fluid components or otherwise to regulate their use more closely. In certain areas of the United States, new drilling permits for hydraulic fracturing have been put on hold pending development of additional standards. The adoption of any future federal, state or local laws or implementing regulations imposing permitting or reporting obligations on, or otherwise limiting, the hydraulic fracturing process could make it more difficult and more expensive to complete crude oil and natural gas wells in low-permeability formations and increase our costs of compliance and doing business, as well as delay, prevent or prohibit the development of natural resources from unconventional formations. 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. 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.

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 increases in drilling activity and competitive pressures resulting from higher crude oil prices.

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 U.S. GAAP. Management believes EBITDAX is useful because it allows us 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 U.S. 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 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 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 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, 2011. At that date, our total funded debt to EBITDAX ratio was 1.0 to 1.0. A violation of this covenant in the future could result in a default under our credit facility. In the event of such default, the lenders under our 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 credit facility were to be accelerated, our assets may not be sufficient to repay in full such indebtedness. Our 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,				
in thousands	2011	2010	2009	2008	2007
Net income	$ 429,072	$ 168,255	$ 71,338	$ 320,950	$ 28,580
Interest expense	76,722	53,147	23,232	12,188	12,939
Provision for income taxes	258,373	90,212	38,670	197,580	268,197
Depreciation, depletion, amortization and accretion	390,899	243,601	207,602	148,902	93,632
Property impairments	108,458	64,951	83,694	28,847	17,879
Exploration expenses	27,920	12,763	12,615	40,160	9,163
Unrealized (gains) losses on derivatives	(4,057)	166,257	2,089		26,703
Non-cash equity compensation	16,572	11,691	11,408	9,081	12,792
EBITDAX	$ 1,303,959	$ 810,877	$ 450,648	$ 757,708	$ 469,885

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 U.S. 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, 2011, our PV-10 totaled approximately $9.2 billion. The Standardized Measure of our discounted future net cash flows was approximately $7.5 billion at December 31, 2011, representing a $1.7 billion difference from PV-10 because of the tax effect. We believe 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 U.S. GAAP. Neither PV-10 nor Standardized Measure represents an estimate of the fair market value of our crude oil and natural gas properties.

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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.

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 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, 2011 and excluding any effect of our derivative instruments in place, our annual revenue would increase or decrease by approximately $165 million for each $10.00 per barrel change in crude oil prices and $37 million for each $1.00 per Mcf change in natural gas prices.

To partially reduce price risk caused by these market fluctuations, we periodically 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 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 limits future revenues from upward price movements.

For the year ended December 31, 2011, we realized gains on natural gas derivatives of $37.3 million and realized losses on crude oil derivatives of $71.4 million. For the year ended December 31, 2011, we reported an unrealized non-cash mark-to-market gain on crude oil derivatives of $18.8 million and an unrealized non-cash mark-to-market loss on natural gas derivatives of $14.7 million. The fair value of our derivative instruments at December 31, 2011 was a net liability of $164.3 million. This liability, representing an unrealized mark-to-market loss, relates to derivative instruments with various terms that are scheduled to be realized over the period from January 2012 through December 2013. Over this period, actual realized derivative settlements may differ significantly, either positively or negatively, from the unrealized mark-to-market valuation at December 31, 2011. An assumed increase in the forward commodity prices used in the year-end valuation of our derivative instruments of $10.00 per barrel for crude oil and $1.00 per MMBtu for natural gas would increase our net derivative liability to approximately $414 million at December 31, 2011. Conversely, an assumed decrease in forward commodity prices of $10.00 per barrel for crude oil and $1.00 per MMBtu for natural gas would change our derivative valuation to a net asset of approximately $75 million at December 31, 2011.

For a further discussion of our hedging activities, see *Part II, Item 7. Management s Discussion and Analysis of Financial Condition and Results of Operations Crude Oil and Natural Gas Hedging* and *Part II, Item 8. Notes to Consolidated Financial Statements Note 5. Derivative Instruments* appearing in this Annual Report.

Credit Risk. We monitor our risk of loss due to non-performance by counterparties of their contractual obligations. Our principal exposure to credit risk is through the sale of our crude oil and natural gas production, which we market to energy marketing companies, refineries and affiliates ($378.8 million in receivables at December 31, 2011), our joint interest receivables ($398.8 million at December 31, 2011), and counterparty credit risk associated with our derivative instrument receivables ($10.3 million at December 31, 2011).

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 which own a partial interest in the wells we operate. These entities participate in our wells primarily based on their ownership in leases included in units 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 generally 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 $52.8 million as of December 31, 2011, 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 facility.

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 $900.0 million of outstanding borrowings under our revolving credit facility at February 15, 2012. The impact of a 1% increase in interest rates on this amount of debt would result in increased interest expense of approximately $9.0 million per year and a $5.6 million decrease in net income per year. Our revolving credit facility matures on July 1, 2015 and the weighted-average interest rate on outstanding borrowings at February 15, 2012 was 2.8%.

The following table presents our long-term debt maturities and the weighted average interest rates by expected maturity date as of December 31, 2011:

In thousands	2012	2013	2014	2015	2016	Thereafter	Total
Fixed rate debt:							
Senior Notes:							
Principal amount (1)	$	$	$	$	$	$ 900.0	$ 900.0
Weighted-average interest rate						7.6%	7.6%
Variable rate debt:							
Revolving credit facility:							
Principal amount	$	$	$	$ 358.0	$	$	$ 358.0
Weighted-average interest rate				2.0%			2.0%

(1) Amount does not reflect the discounts at which the Senior 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 values of our Senior Notes.

Item 8. Financial Statements and Supplementary Data
Index to Consolidated Financial Statements

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REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

Board of Directors and Shareholders

Continental Resources, Inc.

We have audited the accompanying consolidated balance sheets of Continental Resources, Inc. (an Oklahoma corporation) and Subsidiaries (the Company) as of December 31, 2011 and 2010, and the related consolidated statements of income, shareholders equity and cash flows for each of the three years in the period ended December 31, 2011. 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 Subsidiaries as of December 31, 2011 and 2010, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2011, 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), the Company s internal control over financial reporting as of December 31, 2011, 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 24, 2012 expressed an unqualified opinion.

/s/ GRANT THORNTON LLP

Oklahoma City, Oklahoma

February 24, 2012

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Continental Resources, Inc. and Subsidiaries

Consolidated Balance Sheets

	December 31, 2011	December 31, 2010
	In thousands, except par values and share data	
Assets		
Current assets:		
Cash and cash equivalents	$ 53,544	$ 7,916
Receivables:		
Crude oil and natural gas sales	366,441	208,211
Affiliated parties	31,108	20,156
Joint interest and other, net	379,991	254,471
Derivative assets	6,669	21,365
Inventories	41,270	38,362
Deferred and prepaid taxes	47,658	22,672
Prepaid expenses and other	9,692	9,173
Total current assets	936,373	582,326
Net property and equipment, based on successful efforts method of accounting	4,681,733	2,981,991
Net debt issuance costs and other	24,355	27,468
Noncurrent derivative assets	3,625	
Total assets	$ 5,646,086	$ 3,591,785
Liabilities and shareholders equity		
Current liabilities:		
Accounts payable trade	$ 642,889	$ 390,892
Revenues and royalties payable	222,027	133,051
Payables to affiliated parties	9,939	4,438
Accrued liabilities and other	117,674	94,829
Derivative liabilities	116,985	76,771
Current portion of asset retirement obligations	2,287	2,241
Total current liabilities	1,111,801	702,222
Long-term debt	1,254,301	925,991
Other noncurrent liabilities:		
Deferred income tax liabilities	850,282	582,841
Asset retirement obligations, net of current portion	60,338	54,079
Noncurrent derivative liabilities	57,598	112,940
Other noncurrent liabilities	3,640	5,557
Total other noncurrent liabilities	971,858	755,417
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; 180,871,688 shares issued and outstanding at December 31, 2011; 170,408,652 shares issued and outstanding at December 31, 2010	1,809	1,704
Additional paid-in capital	1,110,694	439,900
Retained earnings	1,195,623	766,551
Total shareholders equity	2,308,126	1,208,155

Total liabilities and shareholders equity	$ 5,646,086	$ 3,591,785

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

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Continental Resources, Inc. and Subsidiaries

Consolidated Statements of Income

	Year Ended December 31,		
	2011	2010	2009
	In thousands, except per share data		
Revenues:			
Crude oil and natural gas sales	$ 1,553,629	$ 917,503	$ 584,089
Crude oil and natural gas sales to affiliates	93,790	31,021	26,609
Loss on derivative instruments, net	(30,049)	(130,762)	(1,520)
Crude oil and natural gas service operations	32,419	21,303	17,033
Total revenues	1,649,789	839,065	626,211
Operating costs and expenses:			
Production expenses	135,178	86,557	76,719
Production and other expenses to affiliates	4,632	6,646	16,523
Production taxes and other expenses	143,236	76,659	45,645
Exploration expenses	27,920	12,763	12,615
Crude oil and natural gas service operations	26,735	18,065	10,740
Depreciation, depletion, amortization and accretion	390,899	243,601	207,602
Property impairments	108,458	64,951	83,694
General and administrative expenses	72,817	49,090	41,094
Gain on sale of assets, net	(20,838)	(29,588)	(709)
Total operating costs and expenses	889,037	528,744	493,923
Income from operations	760,752	310,321	132,288
Other income (expense):			
Interest expense	(76,722)	(53,147)	(23,232)
Other	3,415	1,293	952
	(73,307)	(51,854)	(22,280)
Income before income taxes	687,445	258,467	110,008
Provision for income taxes	258,373	90,212	38,670
Net income	$ 429,072	$ 168,255	$ 71,338
Basic net income per share	$ 2.42	$ 1.00	$ 0.42
Diluted net income per share	$ 2.41	$ 0.99	$ 0.42

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

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Continental Resources, Inc. and Subsidiaries

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, 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
Stock-based compensation			11,691		11,691
Excess tax benefit on stock-based compensation			5,230		5,230
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
Net income				429,072	429,072
Public offering of common stock	10,080,000	101	659,131		659,232
Stock-based compensation			16,567		16,567
Stock options:					
Exercised	18,470		13		13
Repurchased and canceled	(2,495)		(150)		(150)
Restricted stock:					
Issued	491,315	5			5
Repurchased and canceled	(82,807)	(1)	(4,767)		(4,768)
Forfeited	(41,447)				
Balance, December 31, 2011	180,871,688	$ 1,809	$ 1,110,694	$ 1,195,623	$ 2,308,126

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

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Continental Resources, Inc. and Subsidiaries

Consolidated Statements of Cash Flows

	Year Ended December 31, 2011	2010	2009
		In thousands	
Cash flows from operating activities:			
Net income	$ 429,072	$ 168,255	$ 71,338
Adjustments to reconcile net income to net cash provided by operating activities:			
Depreciation, depletion, amortization and accretion	391,844	242,748	208,885
Property impairments	108,458	64,951	83,694
Change in fair value of derivatives	(4,057)	166,257	2,089
Stock-based compensation	16,572	11,691	11,408
Provision for deferred income taxes	245,203	77,359	36,119
Excess tax benefit from stock-based compensation		(5,230)	(2,872)
Dry hole costs	7,949	3,024	6,477
Gain on sale of assets, net	(20,838)	(29,588)	(709)
Other, net	3,661	4,366	2,607
Changes in assets and liabilities:			
Accounts receivable	(294,702)	(299,480)	48,738
Inventories	(3,412)	(11,651)	(4,501)
Prepaid expenses and other	(3,329)	(2,398)	21,961
Accounts payable trade	83,907	146,473	(117,643)
Revenues and royalties payable	88,976	66,262	(11,371)
Accrued liabilities and other	20,784	47,842	13,842
Other noncurrent assets and liabilities	(2,173)	2,286	2,924
Net cash provided by operating activities	1,067,915	653,167	372,986
Cash flows from investing activities:			
Exploration and development	(1,925,577)	(1,031,499)	(497,496)
Purchase of crude oil and natural gas properties	(65,315)	(7,338)	(1,217)
Purchase of other property and equipment	(44,750)	(44,564)	(8,257)
Proceeds from sale of assets	30,928	43,985	7,148
Net cash used in investing activities	(2,004,714)	(1,039,416)	(499,822)
Cash flows from financing activities:			
Revolving credit facility borrowings	493,000	341,000	426,100
Repayment of revolving credit facility	(165,000)	(537,000)	(576,500)
Proceeds from issuance of Senior Notes		587,210	297,480
Proceeds from issuance of common stock	659,736		
Other debt			3,304
Repayment of other debt			(3,304)
Debt issuance costs			