

CONTINENTAL RESOURCES INC

Form 10-Q

May 03, 2012

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UNITED STATES
SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

FORM 10-Q

(Mark One)

☒ **QUARTERLY REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**

For the quarterly period ended March 31, 2012

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)

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<p>Oklahoma (State or other jurisdiction of incorporation or organization)</p> <p>20 N. Broadway, Oklahoma City, Oklahoma (Address of principal executive offices)</p> <p style="text-align: right;">(405) 234-9000</p>	<p>73-0767549 (I.R.S. Employer Identification No.)</p> <p>73102 (Zip Code)</p>
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(Registrant's telephone number, including area code)

302 N. Independence, Suite 1500, Enid, Oklahoma 73701

(Former name, former address and former fiscal year, if changed since last report)

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 ☒ No ☐

Indicate by check mark whether the registrant has submitted electronically and posted on its corporate Web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T (§232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files). Yes ☒ No ☐

Indicate by check mark 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 <input checked="" type="checkbox"/>	Accelerated filer <input type="checkbox"/>
Non-accelerated filer <input type="checkbox"/> (Do not check if a smaller reporting company)	Smaller reporting company <input type="checkbox"/>

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

181,028,205 shares of our \$0.01 par value common stock were outstanding on April 27, 2012.

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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.

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

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.

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.

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.

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.

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

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

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.

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.

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MMBtu One million British thermal units. A British thermal unit 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.

MMcf One million cubic feet of natural gas.

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.

NYMEX The New York Mercantile Exchange.

play 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.

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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.

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 geological and/or geophysical analysis and interpretation.

proved reserves The quantities of crude oil and natural gas, which, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be economically producible from a given date forward, from known reservoirs and under existing economic conditions, operating methods, and government regulations prior to the time at which contracts providing the right to operate expire, unless evidence indicates that renewal is reasonably certain.

proved developed reserves Reserves 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.

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.

unconventional play An area believed to be capable of producing crude oil and/or 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 economically producible quantities of crude oil and/or 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.

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.

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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 intended to 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 II, Item 1A. Risk Factors* included in this report, our Annual Report on Form 10-K for the year ended December 31, 2011, registration statements filed from time to time with the SEC, and other announcements we make from time to time.

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;
- 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 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 II, Item 1A. Risk Factors* in this report, our Annual Report on Form 10-K for the year ended December 31, 2011, 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.

Table of Contents**PART I. Financial Information****ITEM 1. Financial Statements****Continental Resources, Inc. and Subsidiaries****Condensed Consolidated Balance Sheets**

	March 31, 2012 <i>(Unaudited)</i> <i>In thousands, except par values and share data</i>	December 31, 2011
Assets		
Current assets:		
Cash and cash equivalents	\$ 42,683	\$ 53,544
Receivables:		
Crude oil and natural gas sales	377,688	366,441
Affiliated parties	26,998	31,108
Joint interest and other, net	392,776	379,991
Derivative assets	14,126	6,669
Inventories	43,162	41,270
Deferred and prepaid taxes	78,213	47,658
Prepaid expenses and other	9,729	9,692
Total current assets	985,375	936,373
Net property and equipment, based on successful efforts method of accounting	5,501,142	4,681,733
Net debt issuance costs and other	40,328	24,355
Noncurrent derivative assets	3,352	3,625
Total assets	\$ 6,530,197	\$ 5,646,086
Liabilities and shareholders' equity		
Current liabilities:		
Accounts payable trade	\$ 604,771	\$ 642,889
Revenues and royalties payable	227,806	222,027
Payables to affiliated parties	8,850	9,939
Accrued liabilities and other	124,735	117,674
Derivative liabilities	205,575	116,985
Current portion of asset retirement obligations	1,742	2,287
Current portion of long-term debt	2,572	
Total current liabilities	1,176,051	1,111,801
Long-term debt, net of current portion	1,891,651	1,254,301
Other noncurrent liabilities:		
Deferred income tax liabilities	923,215	850,282
Asset retirement obligations, net of current portion	51,238	60,338
Noncurrent derivative liabilities	105,324	57,598
Other noncurrent liabilities	3,349	3,640
Total other noncurrent liabilities	1,083,126	971,858
Commitments and contingencies (Note 7)		
Shareholders' equity:		

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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; 181,011,724 shares issued and outstanding at March 31, 2012; 180,871,688 shares issued and outstanding at December 31, 2011

	1,810	1,809
Additional paid-in capital	1,112,842	1,110,694
Retained earnings	1,264,717	1,195,623
Total shareholders' equity	2,379,369	2,308,126
Total liabilities and shareholders' equity	\$ 6,530,197	\$ 5,646,086

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

Table of Contents**Continental Resources, Inc. and Subsidiaries****Unaudited Condensed Consolidated Statements of Operations**

	Three months ended March 31,	
	2012	2011
	<i>In thousands, except per share data</i>	
Revenues		
Crude oil and natural gas sales	\$ 535,312	\$ 316,740
Crude oil and natural gas sales to affiliates	16,946	9,727
Loss on derivative instruments, net	(169,057)	(369,303)
Crude oil and natural gas service operations	11,899	6,626
Total revenues	395,100	(36,210)
Operating costs and expenses		
Production expenses	40,016	28,398
Production and other expenses to affiliates	1,069	872
Production taxes and other expenses	49,730	27,562
Exploration expenses	4,151	6,812
Crude oil and natural gas service operations	9,842	5,451
Depreciation, depletion, amortization and accretion	149,455	75,650
Property impairments	29,907	20,848
General and administrative expenses	24,966	16,347
Gain on sale of assets, net	(49,627)	(15,257)
Total operating costs and expenses	259,509	166,683
Income (loss) from operations	135,591	(202,893)
Other income (expense):		
Interest expense	(24,278)	(18,971)
Other	781	509
	(23,497)	(18,462)
Income (loss) before income taxes	112,094	(221,355)
Provision (benefit) for income taxes	43,000	(84,154)
Net income (loss)	\$ 69,094	\$ (137,201)
Basic net income (loss) per share	\$ 0.38	\$ (0.80)
Diluted net income (loss) per share	\$ 0.38	\$ (0.80)

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

Table of Contents**Continental Resources, Inc. and Subsidiaries****Condensed Consolidated Statements of Shareholders Equity**

	Shares outstanding	Common stock	Additional paid-in capital	Retained earnings	Total shareholders equity
<i>In thousands, except share data</i>					
Balance at December 31, 2011	180,871,688	\$ 1,809	\$ 1,110,694	\$ 1,195,623	\$ 2,308,126
Net income (unaudited)				69,094	69,094
Stock-based compensation (unaudited)			5,836		5,836
Stock options:					
Exercised (unaudited)	86,500		60		60
Repurchased and canceled (unaudited)	(32,984)		(2,951)		(2,951)
Restricted stock:					
Issued (unaudited)	100,795	1			1
Repurchased and canceled (unaudited)	(9,508)		(797)		(797)
Forfeited (unaudited)	(4,767)				
Balance at March 31, 2012	181,011,724	\$ 1,810	\$ 1,112,842	\$ 1,264,717	\$ 2,379,369

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

Table of Contents**Continental Resources, Inc. and Subsidiaries****Unaudited Condensed Consolidated Statements of Cash Flows**

	000000 Three months ended March 31, 2012	000000 March 31, 2011
	<i>In thousands</i>	
Cash flows from operating activities		
Net income (loss)	\$ 69,094	\$ (137,201)
Adjustments to reconcile net income (loss) to net cash provided by operating activities:		
Depreciation, depletion, amortization and accretion	150,273	76,762
Property impairments	29,907	20,848
Change in fair value of derivatives	129,132	364,087
Stock-based compensation	5,515	3,642
Provision (benefit) for deferred income taxes	40,850	(84,154)
Dry hole costs	88	1,504
Gain on sale of assets, net	(49,627)	(15,257)
Other, net	828	929
Changes in assets and liabilities:		
Accounts receivable	(19,921)	(77,631)
Inventories	(2,634)	(13,886)
Prepaid expenses and other	1,484	(513)
Accounts payable trade	(1,768)	3,648
Revenues and royalties payable	5,778	41,569
Accrued liabilities and other	5,948	11,340
Other noncurrent assets and liabilities	(3)	(52)
Net cash provided by operating activities	364,944	195,635
Cash flows from investing activities		
Exploration and development	(1,012,308)	(348,011)
Purchase of crude oil and natural gas properties	(57,662)	
Purchase of other property and equipment	(9,963)	(29,443)
Proceeds from sale of assets	84,818	22,131
Net cash used in investing activities	(995,115)	(355,323)
Cash flows from financing activities		
Revolving credit facility borrowings	718,000	135,000
Repayment of revolving credit facility	(900,000)	(165,000)
Proceeds from issuance of Senior Notes	787,000	
Proceeds from other debt	22,000	
Repayment of other debt	(159)	
Proceeds from issuance of common stock		659,736
Debt issuance costs	(3,843)	(21)
Equity issuance costs		(299)
Repurchase of equity grants	(3,748)	(207)
Exercise of stock options	60	3
Net cash provided by financing activities	619,310	629,212
Net change in cash and cash equivalents	(10,861)	469,524
Cash and cash equivalents at beginning of period	53,544	7,916
Cash and cash equivalents at end of period	\$ 42,683	\$ 477,440

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

Table of Contents**Continental Resources, Inc. and Subsidiaries****Notes to Unaudited Condensed Consolidated Financial Statements*****Note 1. Organization and Nature of Business******Description of the Company***

Continental's principal business is crude oil and natural gas exploration, development and production 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 consists of properties east of the Mississippi river including the Illinois Basin and the state of Michigan. The Company's operations are geographically concentrated in the North region, with that region comprising 76% of the Company's crude oil and natural gas production for the three months ended March 31, 2012. The Company has focused its operations on the exploration and development of crude oil since the 1980s. For the three months ended March 31, 2012, crude oil accounted for 70% of the Company's crude oil and natural gas production and 89% of its crude oil and natural gas revenues.

Note 2. Basis of Presentation and Significant Accounting Policies***Basis of presentation***

The condensed consolidated financial statements include the accounts of Continental and its wholly owned subsidiaries after all significant inter-company accounts and transactions have been eliminated.

This report has been prepared pursuant to the rules and regulations of the Securities and Exchange Commission (the "SEC") applicable to interim financial information. Because this is an interim period filing presented using a condensed format, it does not include all disclosures required by accounting principles generally accepted in the United States ("U.S. GAAP"), although the Company believes the disclosures are adequate to make the information not misleading. You should read this Form 10-Q together with the Company's Annual Report on Form 10-K for the year ended December 31, 2011 ("2011 Form 10-K"), which includes a summary of the Company's significant accounting policies and other disclosures.

The condensed consolidated financial statements as of March 31, 2012 and for the three month periods ended March 31, 2012 and 2011 are unaudited. The condensed consolidated balance sheet as of December 31, 2011 was derived from the audited balance sheet included in the 2011 Form 10-K. The Company has evaluated events or transactions through the date this report on Form 10-Q was filed with the SEC in conjunction with its preparation of these financial statements.

The preparation of financial statements in conformity with U.S. GAAP requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities, the disclosure of contingent assets and liabilities at the date of the financial statements, and the reported amounts of revenues and expenses during the reporting period. Actual results could differ from those estimates. The most significant of the estimates and assumptions that affect reported results are the estimates of the Company's crude oil and natural gas reserves, which are used to compute depreciation, depletion, amortization and impairment of proved crude oil and natural gas properties. In the opinion of management, all adjustments (consisting only of normal recurring adjustments) necessary for a fair presentation in accordance with U.S. GAAP have been included in these unaudited interim condensed consolidated financial statements. The results of operations for any interim period are not necessarily indicative of the results of operations that may be expected for any other interim period or for the entire year.

Inventories

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

<i>In thousands</i>	March 31, 2012	December 31, 2011
Tubular goods and equipment	\$ 15,235	\$ 15,665
Crude oil	27,927	25,605

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Total	\$	43,162	\$	41,270
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Crude oil inventories are valued at the lower of cost or market using the first-in, first-out inventory method. Crude oil inventories consist of the following volumes:

Table of Contents**Continental Resources, Inc. and Subsidiaries****Notes to Unaudited Condensed Consolidated Financial Statements**

<i>In barrels</i>	March 31, 2012	December 31, 2011
Crude oil line fill requirements	291,000	283,000
Temporarily stored crude oil	206,000	152,000
Total	497,000	435,000
<i>Earnings per share</i>		

Basic net income (loss) per share is computed by dividing net income (loss) by the weighted-average number of shares outstanding for the period. Diluted net income (loss) per share reflects the potential dilution of non-vested restricted stock awards and stock options, which are calculated using the treasury stock method as if the awards and options were exercised. The following table presents the calculation of basic and diluted weighted average shares outstanding and net income (loss) per share for the three months ended March 31, 2012 and 2011:

	Three months ended March 31,	
	2012	2011
	<i>In thousands, except per share data</i>	
Income (loss) (numerator):		
Net income (loss) - basic and diluted	\$ 69,094	\$ (137,201)
Weighted average shares (denominator):		
Weighted average shares - basic	179,707	171,729
Non-vested restricted stock	512	
Stock options	64	
Weighted average shares - diluted	180,283	171,729
Net income (loss) per share:		
Basic	\$ 0.38	\$ (0.80)
Diluted	\$ 0.38	\$ (0.80)

The potential dilutive effect of 678,000 weighted average restricted shares and 103,000 weighted average stock options were not included in the calculation of diluted net loss per share for the three months ended March 31, 2011 because to do so would have been anti-dilutive to the earnings per share calculation.

New accounting standard

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 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 became effective in the first interim or annual reporting period beginning after December 15, 2011 and is required to be applied prospectively. The Company adopted the requirements of ASU No. 2011-04 on January 1, 2012, which required additional footnote disclosures and did not have an effect on the Company's financial position, results of operations or cash flows. The required disclosures have been included, as applicable, in *Note 5. Fair Value Measurements*.

Note 3. Supplemental Cash Flow Information

The following table discloses supplemental cash flow information about cash paid for interest and income taxes. Also disclosed is information about investing activities that affects recognized liabilities but does not result in cash receipts or payments.

Table of Contents**Continental Resources, Inc. and Subsidiaries****Notes to Unaudited Condensed Consolidated Financial Statements**

	Three months ended March 31, 2012 2011 <i>In thousands</i>	
Supplemental cash flow information:		
Cash paid for interest	\$ 2,915	\$ 15,908
Cash paid for income taxes	\$ 626	\$ 90
Cash received for income tax refunds	\$ (5)	\$
Non-cash investing activities:		
Asset retirement obligations, net	\$ 1,762	\$ 513

Note 4. Derivative Instruments

The Company is required to recognize all derivative instruments on the balance sheet as either assets or liabilities measured at fair value. The Company has not designated its derivative instruments as hedges for accounting purposes and, as a result, marks its derivative instruments to fair value and recognizes the realized and unrealized changes in fair value of derivative instruments in the unaudited condensed consolidated statements of operations under the caption Loss on derivative instruments, net.

The Company has utilized swap and collar derivative contracts to hedge against the variability in cash flows associated with the forecasted sale of future crude oil and natural gas production. While the use of these derivative instruments limits the downside risk of adverse price movements, their use also limits future revenues from upward price movements.

During the three months ended March 31, 2012, the Company entered into several new swap derivative contracts covering a portion of its forecasted crude oil and natural gas production for 2012, 2013 and 2014. The new contracts were entered into in the ordinary course of business and the Company may enter into additional similar contracts in the future. None of the new contracts have been designated for hedge accounting.

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

All of the Company's derivative contracts are carried at fair value in the condensed consolidated balance sheets under the captions Derivative assets, Noncurrent derivative assets, Derivative liabilities, and Noncurrent derivative liabilities. Derivative assets and liabilities with the same counterparty and subject to contractual terms which provide for net settlement are reported on a net basis in the condensed consolidated balance sheets. The Company's derivative contracts are settled based upon reported settlement prices on commodity exchanges, with crude oil derivative settlements based on NYMEX West Texas Intermediate pricing or Inter-Continental Exchange pricing for Brent crude oil and natural gas derivative settlements based on NYMEX Henry Hub pricing. The estimated fair value of derivative contracts is based upon various factors, including commodity exchange prices, over-the-counter quotations, and, in the case of collars, volatility, the risk-free interest rate, and the time to expiration. The calculation of the fair value of collars requires the use of an option-pricing model. See Note 5. Fair Value Measurements.

At March 31, 2012, the Company had outstanding contracts with respect to future production as set forth in the tables below.

Crude Oil - West Texas Intermediate

		Collars	
	Swaps	Floors	Ceilings

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Period and Type of Contract	Bbls	Weighted Average Price	Range	Weighted Average Price	Range	Weighted Average Price
April 2012 - December 2012						
Swaps - WTI	5,500,000	\$ 88.69				
Collars - WTI	4,006,750		\$ 80.00	\$ 80.00	\$ 93.25-\$97.00	\$ 94.71
January 2013 - December 2013						
Swaps - WTI	5,110,000	\$ 88.63				
Collars - WTI	8,760,000		\$ 80.00-\$95.00	\$ 86.92	\$ 92.30-\$110.33	\$ 99.46
January 2014 - December 2014						
Swaps - WTI	5,566,250	\$ 100.00				

Table of Contents**Continental Resources, Inc. and Subsidiaries****Notes to Unaudited Condensed Consolidated Financial Statements***Crude Oil - ICE Brent*

Period and Type of Contract	Bbls	Weighted Average Price
April 2012 - December 2012		
Swaps - ICE Brent	3,162,500	\$ 111.17
January 2013 - December 2013		
Swaps - ICE Brent	2,372,500	\$ 109.19
<i>Natural Gas - Henry Hub</i>		

Period and Type of Contract	MMBtus	Weighted Average Price
April 2012 - June 2012		
Swaps - Henry Hub	1,820,000	\$ 4.06
July 2012 - December 2012		
Swaps - Henry Hub	11,040,000	\$ 3.45
January 2013 - December 2013		
Swaps - Henry Hub	18,250,000	\$ 3.76
<i>Derivative Fair Value Gain (Loss)</i>		

The following table presents realized and unrealized gains and losses on derivative instruments for the periods presented.

	Three months ended March 31,	
	2012	2011
	<i>In thousands</i>	
Realized gain (loss) on derivatives:		
Crude oil fixed price swaps	\$ (31,424)	\$ (3,095)
Crude oil collars	(10,920)	(10,247)
Natural gas fixed price swaps	2,419	8,126
Total realized gain (loss) on derivatives	\$ (39,925)	\$ (5,216)
Unrealized gain (loss) on derivatives:		
Crude oil fixed price swaps	\$ (80,998)	\$ (165,043)
Crude oil collars	(58,943)	(195,088)
Natural gas fixed price swaps	10,809	(3,956)
Total unrealized gain (loss) on derivatives	\$ (129,132)	\$ (364,087)
Loss on derivative instruments, net	\$ (169,057)	\$ (369,303)

The table below provides balance sheet data about the fair value of derivatives for the periods presented.

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	March 31, 2012			December 31, 2011		
	Assets	(Liabilities)	Net	Assets	(Liabilities)	Net
	Fair	Fair	Fair	Fair	Fair	Fair
	Value	Value	Value	Value	Value	Value
<i>In thousands</i>						
Commodity swaps and collars	\$ 17,478	\$ (310,899)	\$ (293,421)	\$ 10,294	\$ (174,583)	\$ (164,289)

Table of Contents**Continental Resources, Inc. and Subsidiaries****Notes to Unaudited Condensed Consolidated Financial Statements****Note 5. Fair Value Measurements**

The Company follows Accounting Standards Codification Topic 820, *Fair Value Measurements and Disclosures*, which establishes a three-level valuation hierarchy for disclosure of fair value measurements. The valuation hierarchy categorizes assets and liabilities measured at fair value into one of three different levels depending on the observability of the inputs employed in the measurement. The three levels are defined as follows:

Level 1: Observable inputs that reflect unadjusted quoted prices for identical assets or liabilities in active markets as of the reporting date.

Level 2: Observable market-based inputs or unobservable inputs that are corroborated by market data. These are inputs other than quoted prices in active markets included in Level 1, which are either directly or indirectly observable as of the reporting date.

Level 3: Unobservable inputs that are not corroborated by market data and may be used with internally developed methodologies that result in management's best estimate of fair value.

A financial instrument's categorization within the hierarchy is based upon the lowest level of input that is significant to the fair value measurement. Level 1 inputs are given the highest priority in the fair value hierarchy while Level 3 inputs are given the lowest priority. The Company's assessment of the significance of a particular input to the fair value measurement requires judgment and may affect the placement of assets and liabilities within the levels of the hierarchy. As Level 1 inputs generally provide the most reliable evidence of fair value, the Company uses Level 1 inputs when available. The Company's policy is to recognize transfers between the hierarchy levels as of the beginning of the reporting period in which the event or change in circumstances caused the transfer.

Assets and Liabilities Measured at Fair Value on a Recurring Basis

Certain assets and liabilities are reported at fair value on a recurring basis, including the Company's derivative instruments. In determining the fair values of fixed price swaps, a discounted cash flow method is used due to the unavailability of relevant comparable market data for the Company's exact contracts. The discounted cash flow method estimates future cash flows based on quoted forward prices for commodities and a risk-adjusted discount rate. The fair values of fixed price swaps are calculated mainly using significant observable inputs (Level 2). Calculation of the fair values of collar contracts requires the use of an industry-standard option pricing model that considers 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. These assumptions are observable in the marketplace or can be corroborated by active markets or broker quotes and are therefore designated as Level 2 within the valuation hierarchy. The Company's calculation for each of its derivative positions is compared to the counterparty valuation for reasonableness.

The following tables summarize the valuation of financial instruments by pricing levels that were accounted for at fair value on a recurring basis as of March 31, 2012 and December 31, 2011.

Description	00000000	00000000	00000000	00000000
	Fair value measurements at March 31, 2012 using:			
	Level 1	Level 2	Level 3	Total
	<i>In thousands</i>			
Derivative assets (liabilities):				
Fixed price swaps	\$	\$ (173,299)	\$	\$ (173,299)

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Collars		(120,122)		(120,122)
Total	\$	\$ (293,421)	\$	\$ (293,421)
Fair value measurements at December 31, 2011 using:				
Description	Level 1	Level 2	Level 3	Total
<i>In thousands</i>				
Derivative assets (liabilities):				
Fixed price swaps	\$	\$ (103,110)	\$	\$ (103,110)
Collars		(61,179)		(61,179)
Total	\$	\$ (164,289)	\$	\$ (164,289)

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The following table sets forth a reconciliation of changes in the fair value of financial assets and liabilities classified as Level 3 in the fair value hierarchy for the first quarter of 2011. The Company's crude oil collar contracts, which were classified as Level 3 instruments in the fair value hierarchy as of and for the three months ending March 31, 2011, were transferred from Level 3 to Level 2 in the third quarter of 2011 due to the Company's ability to corroborate the volatility factors used to value its collar contracts with observable changes in forward commodity prices.

	2011 <i>In thousands</i>
Balance at January 1, 2011	\$ (103,418)
Total realized or unrealized gains (losses), net:	
Included in earnings	(195,088)
Included in other comprehensive income	
Purchases	
Sales	
Issuances	
Settlements	
Transfers into Level 3	
Transfers out of Level 3	
Balance at March 31, 2011	\$ (298,506)
Unrealized gains (losses) relating to derivatives held at March 31, 2011	\$ (196,675)
Gains and losses included in earnings for the three month periods ended March 31, 2012 and 2011 attributable to the change in unrealized gains and losses relating to derivatives held at March 31, 2012 and 2011 are reported in the unaudited condensed consolidated statements of operations under the caption Loss on derivative instruments, net.	

Assets and Liabilities Measured at Fair Value on a Nonrecurring Basis

Certain assets and liabilities are reported at fair value on a nonrecurring basis in the condensed consolidated financial statements. The following methods and assumptions were used to estimate the fair values for those assets and liabilities.

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

Unobservable Input	Assumption
Proved reserves	Reserves at period end
Forward commodity prices	Forward NYMEX swap prices through 2015, escalating 3% per year thereafter
Operating and development costs	Estimated costs for the current year, escalating 3% per year thereafter
Productive life of field	Ranging from 0 to 50 years

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Discount rate

10%

Fair value measurements of proved properties are performed on at least a quarterly basis, but may be performed more frequently if circumstances indicate the carrying value of a field may be greater than its future net cash flows. Unobservable inputs to the fair value assessment are reviewed quarterly and are revised as warranted based on 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. Fair value measurements of proved properties are reviewed and approved by certain members of the Company's management.

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As a result of changes in commodity futures price strips, proved properties were reviewed for impairment at March 31, 2012 and March 31, 2011. No impairment provisions were recorded for the Company's proved crude oil and natural gas properties for the three month periods ended March 31, 2012 and 2011. For those periods, future cash flows were determined to be in excess of cost basis, therefore no impairment was necessary.

Certain unproved crude oil and natural gas properties were impaired during the three months ended March 31, 2012 and March 31, 2011, reflecting amortization of undeveloped leasehold costs. For individually insignificant unproved properties, impairment losses are recognized by amortizing the portion of the properties' costs which management estimates will not be transferred to proved properties over the lives of the leases based on experience of successful drilling and the average holding period.

The following table sets forth the non-cash impairments of both proved and unproved properties for the indicated periods. Proved and unproved property impairments are recorded under the caption "Property impairments" in the unaudited condensed consolidated statements of operations.

	Three months ended March 31, 2012 2011	
	<i>In thousands</i>	
Proved property impairments	\$	\$
Unproved property impairments	29,907	20,848
Total	\$ 29,907	\$ 20,848

Asset Retirement Obligations The Company's asset retirement obligations (AROs) primarily relate to future plugging and abandonment costs on its crude oil and natural gas properties and related facilities disposal. The fair value of AROs is estimated based on discounted cash flow projections using estimates, assumptions and judgments regarding such factors as the existence of a legal obligation for an ARO, estimated cash flow probabilities, amounts and timing of settlements, the credit-adjusted risk-free rate to be used, and a rate of inflation. The fair values of ARO additions were \$1.2 million and \$0.6 million for the three months ended March 31, 2012 and 2011, respectively, which are reflected in the caption "Asset retirement obligations, net of current portion" in the condensed consolidated balance sheets. The fair values of AROs are calculated using significant unobservable inputs (Level 3). The following table sets forth quantitative information about the significant unobservable inputs used by the Company to calculate the fair value of AROs.

Unobservable Input	Assumption
Estimated costs	Generally ranging from \$5,000 to \$100,000 of gross costs per well, reduced to the Company's working interest
Credit-adjusted risk-free rate	6%
Rate of inflation	3%
Productive life of well	Ranging from 0 to 50 years

The Company initially recognizes an ARO by recording a liability at fair value in the period in which a legal obligation exists along with a corresponding increase in the carrying amount of the related long-lived asset. Unobservable inputs being used in initial fair value assessments are reviewed periodically and are revised as warranted based on the Company's experience with the probability, timing and amounts of ARO settlements or the existence of economic conditions that suggest inflation and discount factors should be reconsidered. Initial fair value measurements of AROs are reviewed and approved by certain members of the Company's management.

Financial Instruments Not Recorded at Fair Value

The following table sets forth the fair values of financial instruments that are not recorded at fair value in the condensed consolidated financial statements.

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<i>In thousands</i>	March 31, 2012		December 31, 2011	
	Carrying Amount	Fair Value	Carrying Amount	Fair Value
Debt:				
Revolving credit facility	\$ 176,000	\$ 176,000	\$ 358,000	\$ 358,000
Note payable	21,841	21,606		
8 1/4% Senior Notes due 2019	297,931	335,250	297,882	331,000
7 3/8% Senior Notes due 2020	198,451	222,333	198,419	219,000
7 1/8% Senior Notes due 2021	400,000	444,507	400,000	435,333
5% Senior Notes due 2022	800,000	804,333		

Total debt \$ 1,894,223 \$ 2,004,029 \$ 1,254,301 \$ 1,343,333

The fair value of the revolving credit facility approximates its carrying value based on borrowing rates available to the Company for bank loans with similar terms and maturities and is classified as Level 2 in the fair value hierarchy.

The fair value of the note payable is determined using a discounted cash flow approach based on the interest rate and payment terms of the note payable and an assumed discount rate. The fair value of the note payable is significantly influenced by the discount rate assumption, which is derived by the Company and is unobservable. Accordingly, the fair value of the note payable is classified as Level 3 in the fair value hierarchy.

The fair values of the 8 1/4% Senior Notes due 2019, the 7 3/8% Senior Notes due 2020, the 7 1/8% Senior Notes due 2021 and the 5% Senior Notes due 2022 are based on quoted market prices and, accordingly, are classified as Level 1 in the fair value hierarchy.

The carrying values of all classes of cash and cash equivalents, trade receivables, and trade payables are considered to be representative of their respective fair values due to the short term maturities of those instruments.

Note 6. Long-Term Debt

Long-term debt consists of the following:

	March 31, 2012	December 31, 2011
	<i>In thousands</i>	
Revolving credit facility	\$ 176,000	\$ 358,000
Note payable	21,841	
8 1/4% Senior Notes due 2019 ⁽¹⁾	297,931	297,882
7 3/8% Senior Notes due 2020 ⁽²⁾	198,451	198,419
7 1/8% Senior Notes due 2021 ⁽³⁾	400,000	400,000
5% Senior Notes due 2022 ⁽³⁾	800,000	
Total debt	\$ 1,894,223	\$ 1,254,301
Less: Current portion of long-term debt	(2,572)	
Long-term debt, net of current portion	\$ 1,891,651	\$ 1,254,301

(1) The carrying amount is net of discounts of \$2.1 million at both March 31, 2012 and December 31, 2011.

(2) The carrying amount is net of discounts of \$1.5 million and \$1.6 million at March 31, 2012 and December 31, 2011, respectively.

(3) These notes were sold at par and are recorded at 100% of face value.

Revolving credit facility

The Company had \$176.0 million of outstanding borrowings at March 31, 2012 on its credit facility, which matures on July 1, 2015. At December 31, 2011, the Company had \$358.0 million of outstanding borrowings on its credit facility. The credit facility had aggregate commitments of \$1.25 billion and a borrowing base of \$2.25 billion at March 31, 2012, subject to semi-annual redetermination. The terms of the facility provide the commitment level can be increased up to the lesser of the borrowing base then in effect or \$2.5 billion. In January 2012, the Company requested, and was granted by the lenders, an increase in the aggregate credit facility commitments from \$750 million to \$1.25 billion, effective January 31, 2012. Borrowings under the facility bear interest, payable quarterly, at a rate per annum equal to the London Interbank Offered Rate (LIBOR) for one, two, three or six months, as elected by the Company, plus a margin ranging from 175 to 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. Credit facility borrowings are required to be secured by the Company's interest in at least 85% (by value) of all of its proved reserves and associated crude oil and natural gas properties.

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Continental Resources, Inc. and Subsidiaries

Notes to Unaudited Condensed Consolidated Financial Statements

The Company had approximately \$1.1 billion of unused commitments (after considering outstanding borrowings and letters of credit) under its credit facility at March 31, 2012 and incurs commitment fees of 0.50% per annum of the daily average amount of unused borrowing availability. The credit agreement contains certain restrictive covenants including a requirement that the Company 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 the credit agreement, the current ratio represents the 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 in *Part I, Item 2. Management's Discussion and Analysis of Financial Condition and Results of Operations - Non-GAAP Financial Measures*. The total funded debt to EBITDAX ratio represents the sum of outstanding borrowings and letters of credit on the credit facility plus the Company's note payable and senior note obligations, divided by total EBITDAX for the most recent four quarters. The Company was in compliance with these covenants at March 31, 2012.

Senior Notes

On March 8, 2012, the Company issued \$800 million of 5% Senior Notes due 2022 (the "2022 Notes") and received net proceeds of approximately \$787.0 million after deducting the initial purchasers' fees. The 2022 Notes were sold at par in a transaction exempt from the registration requirements of the Securities Act to qualified institutional buyers in reliance on Rule 144A of the Securities Act. The net proceeds were used to repay a portion of the borrowings then outstanding under the Company's credit facility.

In connection with the issuance and sale of the 2022 Notes, the Company entered into a registration rights agreement (the "Registration Rights Agreement") with the initial purchasers dated March 8, 2012 to allow holders of the unregistered 2022 Notes to exchange them for registered notes that have substantially identical terms. The Company agreed to use reasonable efforts to cause the exchange to be completed within 400 days after the issuance of the 2022 Notes. The Company is required to pay additional interest if it fails to comply with its obligations to register the 2022 Notes within the specified time period, whereby the interest rate would be increased by 1.0% per annum during the period in which a registration default is in effect. The Company expects to comply with the terms of the Registration Rights Agreement and complete the exchange of the 2022 Notes within the 400 day period.

The 8 1/4% Senior Notes due 2019 (the "2019 Notes"), the 7 3/8% Senior Notes due 2020 (the "2020 Notes"), the 7 1/8% Senior Notes due 2021 (the "2021 Notes"), and the 2022 Notes (collectively, the "Notes") will mature on October 1, 2019, October 1, 2020, April 1, 2021, and September 15, 2022, respectively. Interest on the 2019 Notes, 2020 Notes, and 2021 Notes is payable semi-annually on April 1 and October 1 of each year. Interest on the 2022 Notes is payable semi-annually on March 15 and September 15 of each year, commencing on September 15, 2012. The Company has the option to redeem all or a portion of the 2019 Notes, 2020 Notes, 2021 Notes, and 2022 Notes at any time on or after October 1, 2014, October 1, 2015, April 1, 2016, and March 15, 2017, respectively, at the redemption prices specified in the Notes' respective indentures (together, the "Indentures") plus accrued and unpaid interest. The Company may also redeem the Notes, in whole or in part, at the "make-whole" redemption prices specified in the Indentures plus accrued and unpaid interest at any time prior to October 1, 2014, October 1, 2015, April 1, 2016, and March 15, 2017 for the 2019 Notes, 2020 Notes, 2021 Notes, and 2022 Notes, respectively. In addition, the Company may redeem up to 35% of the 2019 Notes, 2020 Notes, 2021 Notes, and 2022 Notes prior to October 1, 2012, October 1, 2013, April 1, 2014, and March 15, 2015, respectively, under certain circumstances with the net cash proceeds from certain equity offerings. The Notes are not subject to any mandatory redemption or sinking fund requirements.

The Indentures contain certain restrictions on the Company's ability to incur additional debt, pay dividends on common stock, make certain investments, create certain liens on assets, engage in certain transactions with affiliates, transfer or sell certain assets, consolidate or merge, or sell substantially all of the Company's assets. These covenants are subject to a number of important exceptions and qualifications. The Company was in compliance with these covenants at March 31, 2012. One of the Company's subsidiaries, Banner Pipeline Company, L.L.C., which currently has no independent assets or operations, fully and unconditionally guarantees the Notes. The Company's other subsidiary, the value of whose assets and operations are minor, does not guarantee the Notes.

Note payable

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In February 2012, the Company borrowed \$22 million under a 10-year amortizing term loan secured by the Company's corporate office building in Oklahoma City, Oklahoma. The loan bears interest at a fixed rate of 3.14% per annum. Principal and interest are payable monthly through the loan's maturity date of February 26, 2022. Accordingly, approximately \$2.6 million is reflected as a current liability under the caption "Current portion of long-term debt" in the condensed consolidated balance sheets as of March 31, 2012.

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Notes to Unaudited Condensed Consolidated Financial Statements

Note 7. Commitments and Contingencies

Drilling commitments As of March 31, 2012, the Company had drilling rig contracts with various terms extending through August 2014. These contracts were entered into in the ordinary course of business to ensure rig availability to allow the Company to execute its business objectives in its key strategic plays. Future commitments as of March 31, 2012 total approximately \$189 million, of which \$138 million is expected to be incurred in the remainder of 2012, \$45 million in 2013, and \$6 million in 2014. These drilling commitments are not recorded in the accompanying condensed consolidated balance sheets.

Fracturing and well stimulation service agreements The Company has 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 the Company's properties in North Dakota and Montana. The agreement has a term of three years, beginning in October 2010, with two one-year extensions available to the Company at its discretion. Pursuant to the take-or-pay provisions, the Company is to 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. The agreement also stipulates the Company will bear the cost of certain products and materials used. Future commitments remaining as of March 31, 2012 amount to approximately \$33 million, of which \$17 million is expected to be incurred in the remainder of 2012 and \$16 million in 2013. Since the inception of this agreement, the Company has been using the services more than the minimum number of days each quarter. Additionally, the Company has an agreement whereby a third party will provide coiled tubing well stimulation services for certain of the Company's properties in Oklahoma at a fixed rate per month for calendar year 2012, resulting in total future commitments of approximately \$4 million as of March 31, 2012. The commitments under these agreements are not recorded in the accompanying condensed consolidated balance sheets.

Firm transportation commitments The Company has a five-year firm transportation commitment, beginning in August 2011, to guarantee pipeline access 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 commitment requires the Company to pay escalating per-barrel transportation charges totaling approximately \$7 million annually through August 2016 regardless of the amount of pipeline capacity used. Additionally, the Company has entered into firm transportation commitments to guarantee capacity on rail transportation facilities. The rail commitments have various terms ranging from three months to four years that extend through December 2015 and require the Company to pay varying per-barrel transportation charges on volumes ranging from 1,000 to 10,000 barrels of crude oil per day. Future commitments remaining as of March 31, 2012 under the rail transportation arrangements amount to approximately \$77 million, of which \$25 million is expected to be incurred in the remainder of 2012, \$35 million in 2013, \$10 million in 2014, and \$7 million in 2015. These pipeline and rail transportation commitments are for crude oil production in the Bakken field where the Company allocates a significant portion of its capital expenditures. The commitments under these arrangements are not recorded in the accompanying condensed consolidated balance sheets. The Company is not committed under these contracts, or any other existing contract, to deliver fixed and determinable quantities of crude oil or natural gas in the future.

Litigation 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 effect on its financial condition, results of operations or cash flows. As of March 31, 2012 and December 31, 2011, the Company has recorded a liability in the condensed consolidated balance sheets under the caption "Other noncurrent liabilities" of \$2.3 million and \$2.6 million, respectively, for various matters, none of which are believed to be individually significant.

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Employee retirement plan The Company maintains a defined contribution retirement plan for its employees and makes contributions to the plan, up to the contribution limits established by the Internal Revenue Service, based on a percentage of each eligible employee's compensation. During 2011, the Company's contributions to the plan represented 3% of eligible employees' compensation, including bonuses, in addition to matching 50% of eligible employees' contributions up to 6% of eligible compensation. Effective January 1, 2012, contributions to the plan represent 3% of eligible employees' compensation, including bonuses, in addition to matching 100% of eligible employees' contributions up to 4% of eligible compensation. Expenses associated with the plan amounted to \$1.0 million and \$0.9 million for the three months ended March 31, 2012 and 2011, respectively.

Employee health claims The Company generally self-insures employee health claims up to the first \$125,000 per employee per year. Amounts paid above this level are reinsured through third-party providers. The Company generally self-insures employee workers' compensation claims up to the first \$300,000 per employee per claim. Amounts paid above this level are reinsured through third-party providers up to \$1 million in excess of the self-insured retention. The Company accrues for claims that have been incurred but not yet reported based on a review of claims filed versus expected claims based on claims history. The accrued liability for health and workers' compensation claims was \$3.2 million and \$2.7 million at March 31, 2012 and December 31, 2011, respectively.

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

Note 8. Stock-Based Compensation

The Company has granted stock options and restricted stock to employees and directors pursuant to the Continental Resources, Inc. 2000 Stock Option Plan (2000 Plan) and the Continental Resources, Inc. 2005 Long-Term Incentive Plan (2005 Plan) as discussed below. The Company's associated compensation expense, which is included in the caption "General and administrative expenses" in the unaudited condensed consolidated statements of operations, is reflected in the table below for the periods presented.

	Three months ended March 31,	
	2012	2011
	<i>In thousands</i>	
Non-cash equity compensation	\$ 5,515	\$ 3,642
<i>Stock Options</i>		

Effective October 1, 2000, the Company adopted the 2000 Plan and granted stock options to certain eligible employees. These grants consisted of either incentive stock options, nonqualified stock options or a combination of both. The granted stock options vested ratably over either a three or five-year period commencing on the first anniversary of the grant date and expired ten years from the date of grant. On November 10, 2005, the 2000 Plan was terminated. As of March 31, 2012, all options issued under the 2000 Plan have been exercised or expired.

The Company's stock option activity under the 2000 Plan for the three months ended March 31, 2012 is presented below:

	Outstanding		Exercisable	
	Number of	Weighted	Number of	Weighted
	stock options	average	stock options	average
		exercise		exercise
		price		price
Outstanding at December 31, 2011	86,500	\$ 0.71	86,500	\$ 0.71
Exercised	(86,500)	0.71	(86,500)	0.71

Outstanding at March 31, 2012

The intrinsic value of a stock option is the amount by which the value of the underlying stock exceeds the exercise price of the option at its exercise date. The total intrinsic value of options exercised during the three months ended March 31, 2012 was \$7.6 million.

Restricted Stock

On October 3, 2005, the Company adopted the 2005 Plan and reserved a maximum of 5,500,000 shares of common stock that may be issued pursuant to the 2005 Plan. As of March 31, 2012, the Company had 2,544,767 shares of restricted stock available to grant to directors, officers and key employees under the 2005 Plan. Restricted stock is awarded in the name of the recipient and except for the right of disposal, constitutes issued and outstanding shares of the Company's common stock for all corporate purposes during the period of restriction including the right to receive dividends, subject to forfeiture. Restricted stock grants generally vest over periods ranging from one to three years.

A summary of changes in the non-vested shares of restricted stock for the three months ended March 31, 2012 is presented below:

	Number of non-vested shares	Weighted average grant-date fair value
Non-vested restricted shares at December 31, 2011	1,198,344	\$ 48.66
Granted	100,795	91.43
Vested	(39,514)	46.60
Forfeited	(4,767)	62.99
Non-vested restricted shares at March 31, 2012	1,254,858	\$ 52.11

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Continental Resources, Inc. and Subsidiaries

Notes to Unaudited Condensed Consolidated Financial Statements

The fair value of restricted stock represents the average of the high and low intraday market prices of the Company's common stock on the date of grant. Compensation expense for a restricted stock grant is a fixed amount determined at the grant date fair value and is recognized ratably over the vesting period as services are rendered by employees and directors. The expected life of restricted stock is based on the non-vested period that remains subsequent to the date of grant. There are no post-vesting restrictions related to the Company's restricted stock. The fair value of restricted stock that vested during the three months ended March 31, 2012 at the vesting date was \$3.1 million. As of March 31, 2012, there was \$43.3 million of unrecognized compensation expense related to non-vested restricted stock. This expense is expected to be recognized ratably over a weighted average period of 1.6 years.

Note 9. Property Acquisition and Dispositions

Acquisition

In February 2012, the Company acquired certain producing and undeveloped properties in the Bakken play of North Dakota from a third party for approximately \$276 million of cash. In the transaction, the Company acquired interests in approximately 23,100 net acres as well as producing properties with production of approximately 1,000 net barrels of oil equivalent per day. The transaction closed on February 15, 2012. The Company's condensed consolidated financial statements include the results of operations and cash flows for the acquired properties subsequent to the closing date.

Dispositions

In February 2012, the Company assigned certain non-strategic leaseholds and producing properties located in the state of Wyoming to a third party for cash proceeds of \$84.4 million. In connection with the transaction, the Company recognized a pre-tax gain of \$50.1 million, which includes the effect of removing \$11.1 million of asset retirement obligations for the disposed properties previously recognized by the Company that were assumed by the buyer. The disposed properties comprised 3.2 MMBoe, or 1%, of the Company's total proved reserves at December 31, 2011 and 259 MBoe, or 1%, of its 2011 total crude oil and natural gas production. In March 2011, the Company assigned certain non-strategic leaseholds located 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. The 2011 transaction involved undeveloped acreage with no proved reserves and no production or revenues. The gains on these transactions are included in Gain on sale of assets, net in the unaudited condensed consolidated statements of operations.

Note 10. Proposed Property Transaction with Related Party

On March 27, 2012, the Company entered into an agreement to purchase the right, title and interest in and to certain crude oil and natural gas properties of Wheatland Oil Inc. (Wheatland) in which the Company also owns an interest. Wheatland is an independent exploration and production company that participates in several of the Company's crude oil and natural gas properties located in the states of North Dakota, Montana, Oklahoma and Mississippi. Wheatland's assets included in the transaction comprise approximately 37,900 net acres in the Bakken play of North Dakota and Montana and interests in producing properties with production of approximately 2,500 net barrels of oil equivalent per day. Harold G. Hamm indirectly and Jeffrey B. Hume own 75% and 25%, respectively, of Wheatland. Mr. Hamm, the Company's Chief Executive Officer, Chairman of the Board and principal shareholder, is the trustee and sole beneficiary of a trust that owns his shares of Wheatland. Mr. Hume is President and Chief Operating Officer of the Company.

The transaction is subject to shareholder approval and had not been consummated at March 31, 2012. The Company is seeking a shareholder vote on the proposed transaction as required under New York Stock Exchange rules and the terms of the purchase and sale agreement. The purchase and sale agreement requires the Company to obtain approval of a majority of the issued and outstanding shares held by shareholders other than members of Continental Resources' Board of Directors, its executive officers, Mr. Hamm and his affiliates, and Mr. Hume and his affiliates. If the transaction is not approved by such shareholders, the purchase and sale agreement will terminate without the payment of fees by either party.

The proposed purchase price for the assets is \$340 million, subject to customary purchase price adjustments. The adjusted purchase price will be paid in shares of the Company's common stock, par value \$0.01 per share, and is anticipated to result in the issuance of between 3.90 million and 4.25 million shares depending on the daily sales prices of the Company's common stock for a period prior to the closing of the transaction. The

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actual number of shares of common stock to be issued will not be known until the closing of the transaction and the determination of any purchase price adjustments. The adjusted purchase price could be more or less than \$340 million.

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Continental Resources, Inc. and Subsidiaries

Notes to Unaudited Condensed Consolidated Financial Statements

Note 11. Relocation of Corporate Headquarters

In March 2011, the Company announced plans to relocate its corporate headquarters from Enid, Oklahoma to Oklahoma City, Oklahoma. The relocation is expected to provide more convenient access to the Company's operations across the country, to its business partners and to an expanded pool of technical talent. The relocation is expected to be completed in the second half of 2012. The Company currently estimates it may incur a total of approximately \$15 million to \$25 million of costs in connection with its relocation, with the majority of the costs expected to be incurred in the second and third quarters of 2012. The Company expects to recognize the majority of relocation costs in its consolidated financial statements when incurred. During the three months ended March 31, 2012, the Company recognized approximately \$1.7 million of costs associated with its relocation efforts, which are included in the caption "General and administrative expenses" in the unaudited condensed consolidated statements of operations. Cumulative relocation costs recognized through March 31, 2012 totaled approximately \$5 million.

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ITEM 2. 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 included in our Annual Report on Form 10-K for the year ended December 31, 2011. Our operating results for the periods discussed may not be indicative of future performance. The following discussion and analysis includes forward-looking statements and should be read in conjunction with the risk factors described under the heading *Part II, Item 1A. Risk Factors* included in this report, if any, and in our Annual Report on Form 10-K for the year ended December 31, 2011, 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. Our operations are geographically concentrated in the North region, with that region comprising 76% of our crude oil and natural gas production for the three months ended March 31, 2012.

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 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.

For the first quarter of 2012, our crude oil and natural gas production averaged 85,526 Boe per day, a 14% increase over average daily production of 75,219 Boe per day for the fourth quarter of 2011 and a 66% increase over average daily production of 51,663 Boe per day for the first quarter of 2011. Crude oil accounted for 70% of our 2012 first quarter production. The increase in 2012 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 3,812 MBoe for the first quarter of 2012, a 17% increase over the fourth quarter of 2011 and a 109% increase over the first quarter of 2011. Our production in the Anadarko Woodford play totaled 1,167 MBoe in the first quarter of 2012, 29% higher than the fourth quarter of 2011 and 383% higher than the first quarter of 2011.

Our crude oil and natural gas revenues for the first quarter of 2012 increased 69% to \$552.3 million due to a 69% increase in sales volumes compared to the same period in 2011. Crude oil accounted for 89% of our total crude oil and natural gas revenues for the three month periods ended March 31, 2012 and 2011.

Our cash flows from operating activities for the first quarter of 2012 were \$364.9 million, an increase from \$195.6 million provided by our operating activities during the comparable 2011 period. The increase in operating cash flows was primarily due to increased crude oil and natural gas revenues as a result of increased 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 over the past year.

During the first quarter of 2012, we invested \$1,045.1 million in our capital program (including \$2.6 million of seismic costs and excluding \$37.4 million of capital costs associated with reduced accruals for capital expenditures), focusing primarily on increased development in the Bakken field of North Dakota and Montana and the Anadarko Woodford play in Oklahoma. Our 2012 first quarter capital expenditures include an unbudgeted acquisition of producing and undeveloped properties in the Bakken play of North Dakota in February 2012 for \$276 million, comprised of interests in approximately 23,100 net acres and production of approximately 1,000 net Boe per day. We expect to continue participating as a buyer of properties when and if we have the ability to increase our position in strategic plays at favorable terms.

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In February 2012, we assigned certain non-strategic leaseholds and producing properties located in the state of Wyoming to a third party for cash proceeds of \$84.4 million and recognized a pre-tax gain on the transaction of \$50.1 million. The disposed properties comprised 3.2 MMBoe, or 1%, of our total proved reserves at December 31, 2011 and 259 MBoe, or 1%, of our 2011 total crude oil and natural gas production.

In January 2012, we were granted 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 2014. We expect our cash flows from operations, our remaining cash balance, and amounts available under 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.

	Three months ended March 31,	
	2012	2011
Average daily production:		
Crude oil (Bbl per day)	59,901	38,446
Natural gas (Mcf per day)	153,751	79,297
Crude oil equivalents (Boe per day)	85,526	51,663
Average sales prices: ⁽¹⁾		
Crude oil (\$/Bbl)	\$ 90.58	\$ 85.34
Natural gas (\$/Mcf)	4.48	5.09
Crude oil equivalents (\$/Boe)	71.39	71.14
Production expenses (\$/Boe) ⁽¹⁾	5.18	6.38
General and administrative expenses (\$/Boe) ^{(1) (2)}	3.23	3.56
Net income (loss) (in thousands)	69,094	(137,201)
Diluted net income (loss) per share	0.38	(0.80)
EBITDAX (in thousands) ⁽³⁾	454,532	268,655

(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 \$0.71 per Boe and \$0.79 per Boe for the three months ended March 31, 2012 and 2011, respectively, and corporate relocation expenses of \$0.23 per Boe for the three months ended

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March 31, 2012.

- (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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Three months ended March 31, 2012 compared to the three months ended March 31, 2011

Results of Operations

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

	Three months ended March 31, 2012 2011	
	<i>In thousands, except sales price data</i>	
Crude oil and natural gas sales	\$ 552,258	\$ 326,467
Loss on derivative instruments, net ⁽¹⁾	(169,057)	(369,303)
Crude oil and natural gas service operations	11,899	6,626
Total revenues	395,100	(36,210)
Operating costs and expenses ⁽²⁾	259,509	166,683
Other expenses, net	23,497	18,462
Income (loss) before income taxes	112,094	(221,355)
Provision (benefit) for income taxes	43,000	(84,154)
Net income (loss)	\$ 69,094	\$ (137,201)
Production volumes:		
Crude oil (MBbl) ⁽³⁾	5,451	3,460
Natural gas (MMcf)	13,991	7,137
Crude oil equivalents (MBoe)	7,783	4,650
Sales volumes:		
Crude oil (MBbl) ⁽³⁾	5,404	3,400
Natural gas (MMcf)	13,991	7,137
Crude oil equivalents (MBoe)	7,736	4,589
Average sales prices: ⁽⁴⁾		
Crude oil (\$/Bbl)	\$ 90.58	\$ 85.34
Natural gas (\$/Mcf)	4.48	5.09
Crude oil equivalents (\$/Boe)	71.39	71.14

(1) Amounts include unrealized non-cash mark-to-market losses on derivative instruments of \$129.1 million and \$364.1 million for the three months ended March 31, 2012 and 2011, respectively.

(2) Net of gain on sale of assets of \$49.6 million and \$15.3 million for the three months ended March 31, 2012 and 2011, respectively.

(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 47 MBbls less than crude oil production for the three months ended March 31, 2012 and 60 MBbls less than crude oil production for the three months ended March 31, 2011.

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

Production

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

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	Three months ended March 31, 2012		2011		Volume increase	Percent increase
	Volume	Percent	Volume	Percent		
Crude oil (MBbl)	5,451	70%	3,460	74%	1,991	58%
Natural gas (MMcf)	13,991	30%	7,137	26%	6,854	96%
Total (MBoe)	7,783	100%	4,650	100%	3,133	67%

	Three months ended March 31, 2012		2011		Volume increase	Percent increase
	MBoe	Percent	MBoe	Percent		
North Region	5,905	76%	3,660	79%	2,245	61%
South Region	1,770	23%	886	19%	884	100%
East Region	108	1%	104	2%	4	4%
Total	7,783	100%	4,650	100%	3,133	67%

Crude oil production volumes increased 58% during the three months ended March 31, 2012 compared to the three months ended March 31, 2011. Production increases in the Bakken field and the Anadarko Woodford play contributed incremental production volumes in 2012 of 1,846 MBbls, a 90% increase over production in these areas for the first quarter of 2011. Production growth in these areas is primarily due to increased drilling and completion activity resulting from our drilling program. Additionally, production from the Red River units increased 124 MBbls, or 10%, in 2012 due to new wells being completed and enhanced recovery techniques being successfully applied.

Natural gas production volumes increased 6,854 MMcf, or 96%, during the three months ended March 31, 2012 compared to the same period in 2011. Natural gas production in the Bakken field increased 2,086 MMcf, or 126%, for the three months ended March 31, 2012 compared to the same period in 2011 due to new wells being completed and gas from existing wells being connected to natural gas processing plants in the play. We expect natural gas production growth in the Bakken field 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 4,831 MMcf, or 370%, due to additional wells being completed and producing in the three months ended March 31, 2012 compared to the same period in 2011. Further, natural gas production increased 248 MMcf in non-Bakken areas of our North region due to the completion of new wells during the period. These increases were partially offset by a 209 MMcf decrease in natural gas production from our Arkoma Woodford properties, which consist primarily of dry gas. We have scaled back our Arkoma Woodford drilling program due to the unfavorable pricing environment for dry gas, instead choosing to focus on liquids-rich portions of the Anadarko Woodford play.

Revenues

Our total revenues consist 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. We have entered into a number of derivative instruments, including fixed price swaps and zero-cost collars, to reduce the uncertainty of future cash flows in order to underpin our capital expenditures and drilling program through 2014. Changes in commodity futures price strips during the first quarter of 2012 and 2011 had a negative impact on the fair value of our derivatives, which resulted in negative revenue adjustments of \$169.1 million and \$369.3 million for the three month periods ended March 31, 2012 and 2011, respectively. We expect our revenues will continue to be significantly impacted, either positively or negatively, by changes in the fair value of our derivative instruments as a result of volatility in crude oil and natural gas prices.

Crude Oil and Natural Gas Sales. Crude oil and natural gas sales for the three months ended March 31, 2012 were \$552.3 million, a 69% increase from sales of \$326.5 million for the same period in 2011. Our sales volumes increased 3,147 MBoe, or 69%, over the same period in 2011 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 \$0.25 to \$71.39 for the three months ended March 31, 2012 from \$71.14 for the three months ended March 31, 2011.

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The differential between NYMEX calendar month average crude oil prices and our realized crude oil price per barrel for the three months ended March 31, 2012 was \$12.27 compared to \$9.21 for the three months ended March 31, 2011 and \$6.39 for the year ended December 31, 2011. Factors contributing to the changing differential included a continued increase in crude oil production in the Williston Basin during the first quarter of 2012 resulting from increased industry production in the Bakken play and higher Canadian crude oil imports, all aided by a mild winter season. Additionally, pipeline transportation capacity constraints in the Williston Basin did not improve during the first quarter. These factors had a negative effect on our realized crude oil prices during the first quarter of 2012 and resulted in higher differentials compared to 2011.

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 unaudited condensed consolidated statements of operations under the caption "Loss on derivative instruments, net", which is a component of total revenues.

During the three months ended March 31, 2012, we realized losses on crude oil derivatives of \$42.3 million and realized gains on natural gas derivatives of \$2.4 million. During the three months ended March 31, 2012, we reported an unrealized non-cash mark-to-market loss on crude oil derivatives of \$139.9 million and a non-cash mark-to-market gain on natural gas derivatives of \$10.8 million. The unrealized mark-to-market gains and losses relate to derivative instruments with various terms that are scheduled to be realized over the period from April 2012 to December 2014. Over this period, actual realized derivative settlements may differ significantly from the unrealized mark-to-market valuation at March 31, 2012. During the three months ended March 31, 2011, we realized losses on crude oil derivatives of \$13.3 million and realized gains on natural gas derivatives of \$8.1 million. During the three months ended March 31, 2011, we reported unrealized non-cash mark-to-market losses on crude oil derivatives of \$360.1 million and natural gas derivatives of \$4.0 million. Derivative losses exceeded crude oil and natural gas sales for the first quarter of 2011, resulting in negative total revenues for that period.

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.

Reclaimed crude oil sales	Three months ended March 31,		
	2012	2011	Increase
Average sales price (\$/Bbl)	\$ 100.30	\$ 89.40	\$ 10.90
Sales volumes (barrels)	85,000	52,000	33,000

Sales of reclaimed crude oil increased 33,000 barrels for the three months ended March 31, 2012 compared to the 2011 first quarter due to increased sales activity from our central treating units. Additionally, prices realized for reclaimed crude oil sales were \$10.90 per barrel higher for the three months ended March 31, 2012 than the comparable 2011 period. These factors contributed to an increase in reclaimed crude oil revenue of \$3.9 million to \$8.5 million and contributed to an overall increase in crude oil and natural gas service operations revenue of \$5.3 million for the three months ended March 31, 2012. Also contributing to the increase in crude oil and natural gas service operations revenue was a \$1.0 million increase in saltwater disposal income resulting from increased activity. Associated crude oil and natural gas service operations expenses increased \$4.3 million to \$9.8 million during the three months ended March 31, 2012 from \$5.5 million during the three months ended March 31, 2011 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 37% to \$40.1 million during the three months ended March 31, 2012 from \$29.3 million during the three months ended March 31, 2011. This increase is primarily the result of higher production volumes from an increase in the number of producing wells. Production expense per Boe was \$5.18 for the three months ended March 31, 2012 compared to \$6.38 per Boe for the three months ended March 31, 2011.

Production taxes and other expenses increased \$23.2 million, or 84%, to \$50.7 million during the three months ended March 31, 2012 compared to the three months ended March 31, 2011 primarily as a result of higher crude oil and natural gas revenues resulting from increased sales volumes. 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 \$5.4 million and \$2.2 million for the three months ended March 31, 2012 and 2011, respectively. The increase in other charges is primarily due to the significant increase in natural gas sales volumes in 2012. Production taxes, excluding other charges, as a percentage of crude oil and natural gas

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revenues were 8.1% for the three months ended March 31, 2012 compared to 7.8% for the three months ended March 31, 2011. The increase is due to higher taxable revenues coming from 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 for the periods presented:

<i>\$/Boe</i>	Three months ended March 31,	
	2012	2011
Production expenses	\$ 5.18	\$ 6.38
Production taxes and other expenses	6.56	6.01

Production expenses, production taxes and other expenses	\$ 11.74	\$ 12.39
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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 presented.

<i>(in thousands)</i>	Three months ended March 31,	
	2012	2011
Geological and geophysical costs	\$ 4,063	\$ 5,308
Dry hole costs	88	1,504

Exploration expenses	\$ 4,151	\$ 6,812
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Geological and geophysical costs decreased \$1.2 million for the three months ended March 31, 2012 due to a decrease in acquisitions of seismic data. No significant dry holes were drilled during the three months ended March 31, 2012.

Depreciation, Depletion, Amortization and Accretion (DD&A). Total DD&A increased \$73.8 million, or 98%, in the first quarter of 2012 compared to the first quarter of 2011, primarily due to a 67% increase in production volumes. The following table shows the components of our DD&A on a unit of sales basis.

<i>\$/Boe</i>	Three months ended March 31,	
	2012	2011
Crude oil and natural gas	\$ 18.92	\$ 16.07
Other equipment	0.30	0.25
Asset retirement obligation accretion	0.10	0.17

Depreciation, depletion, amortization and accretion	\$ 19.32	\$ 16.49
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The increase in DD&A per Boe is 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 costs of developing reserves in those areas compared to our older, more mature properties.

Property Impairments. Property impairments increased in the three months ended March 31, 2012 by \$9.1 million to \$29.9 million compared to \$20.8 million for the three months ended March 31, 2011.

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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 \$9.1 million during the three months ended March 31, 2012 to \$29.9 million compared to \$20.8 million for the three months ended March 31, 2011. The increase resulted from a larger base of amortizable costs 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, resulting in higher amortization of costs in 2012. We currently have no individually significant non-producing properties that would be assessed for impairment on a property-by-property basis.

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. No impairment provisions for proved properties were recognized for the three month periods ended March 31, 2012 and 2011. For those periods, future cash flows were determined to be in excess of cost basis, therefore no impairment was necessary.

General and Administrative Expenses. General and administrative expenses (G&A) increased \$8.7 million to \$25.0 million for the three months ended March 31, 2012 from \$16.3 million for the comparable period in 2011. G&A expenses include non-cash charges for equity compensation of \$5.5 million and \$3.6 million for the three months ended March 31, 2012 and 2011, respectively. The increase in equity compensation in 2012 resulted from larger grants of restricted stock throughout 2011 due to employee growth along with an increase in our grant-date stock prices, which resulted in increased expense recognition in the first quarter of 2012 compared to the first quarter of 2011. G&A expenses excluding equity compensation increased \$6.8 million for the three months ended March 31, 2012 compared to the same period in 2011. 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 521 total employees in March 2011 to 656 total employees in March 2012, a 26% increase. In March 2011, we announced plans to relocate our corporate headquarters from Enid, Oklahoma to Oklahoma City, Oklahoma. The relocation 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 the second half of 2012. For the three months ended March 31, 2012, we have recognized approximately \$1.7 million of costs in general and administrative expenses associated with the relocation. Cumulative relocation costs recognized through March 31, 2012 totaled approximately \$5 million. We currently expect to incur a total of approximately \$15 million to \$25 million of costs in connection 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 for the periods presented.

	Three months ended March 31,	
\$/Boe	2012	2011
General and administrative expenses	\$ 2.29	\$ 2.77
Non-cash equity compensation	0.71	0.79
Corporate relocation expenses	0.23	

General and administrative expenses	\$ 3.23	\$ 3.56
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Interest Expense. Interest expense increased \$5.3 million, or 28%, for the three months ended March 31, 2012 compared to the three months ended March 31, 2011 due to an increase in our weighted average outstanding long-term debt obligations. Our weighted average outstanding long-term debt balance for the three months ended March 31, 2012 was \$1,594.7 million with a weighted average interest rate of 5.2% compared to a weighted average outstanding long-term debt balance of \$971.9 million and a weighted average interest rate of 7.3% for the comparable period in 2011. The increase in outstanding debt resulted from higher borrowings incurred to fund increased amounts of capital expenditures and property acquisitions in the first quarter of 2012 compared to the first quarter of 2011. On March 8, 2012, we issued \$800 million of 5% Senior Notes due 2022 and used the net proceeds to repay credit facility borrowings.

Our weighted average outstanding credit facility balance increased to \$484.5 million for the first quarter of 2012 compared to \$71.9 million for the first quarter of 2011. The weighted average interest rate on our credit facility borrowings was 2.5% for the first quarter of 2012 compared to 2.7% for the same period in 2011. At March 31, 2012, we had \$176.0 million of outstanding borrowings on our credit facility at a weighted average interest rate of 2.0%.

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Income Taxes. We recorded income tax expense for the three months ended March 31, 2012 of \$43.0 million compared to an income tax benefit of \$84.2 million for the three months ended March 31, 2011. We provide for income taxes at a combined federal and state tax rate of approximately 38% after taking into account permanent taxable differences.

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. The 69% increase in sales volumes for the first three months of 2012 compared to the same period in 2011 resulted in improved cash flows from operations and better liquidity. Further, our liquidity has improved in 2012 as we have more borrowing availability on our credit facility resulting from the January 2012 increase in our credit facility's aggregate commitments from \$750 million to \$1.25 billion, coupled with the repayment of credit facility borrowings using proceeds from the March 2012 issuance of \$800 million of 5% Senior Notes due 2022 as discussed below under the heading *Issuance of Long-Term Debt*.

At March 31, 2012, we had \$42.7 million of cash and cash equivalents and approximately \$1.1 billion of available capacity under our credit facility after considering outstanding borrowings and letters of credit.

Cash Flows

Cash Flows from Operating Activities

Our net cash provided by operating activities was \$364.9 million and \$195.6 million for the three months ended March 31, 2012 and 2011, respectively. The increase in operating cash flows was primarily due to higher crude oil and natural gas revenues as a result of higher 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.

Cash Flows used in Investing Activities

During the three months ended March 31, 2012 and 2011, we had cash flows used in investing activities (excluding asset sales) of \$1,079.9 million and \$377.5 million, respectively, related to our capital program, inclusive of dry hole costs. The increase in cash flows used in investing activities in 2012 was primarily due to our drilling program, primarily in the North Dakota Bakken field and the liquids-rich Anadarko Woodford play in Oklahoma, coupled with an increase in property acquisitions in the current period, most notably the February 2012 acquisition of producing and non-producing properties in North Dakota for \$276 million. The use of cash for capital expenditures was partially offset by proceeds received from asset dispositions. Proceeds from the sale of assets amounted to \$84.8 million for the first quarter of 2012, primarily related to our February 2012 disposition of certain Wyoming properties for proceeds of \$84.4 million. Proceeds from the sale of assets amounted to \$22.1 million for the first quarter of 2011, primarily related to our March 2011 disposition of certain Michigan properties for proceeds of \$22.0 million.

Cash Flows from Financing Activities

Net cash provided by financing activities for the three months ended March 31, 2012 was \$619.3 million resulting from the receipt of \$787.0 million of net proceeds, after deducting the initial purchasers' fees, from the issuance of the \$800 million of 2022 Notes in March 2012, partially offset by net repayments of \$182.0 million on our credit facility and \$3.8 million of costs incurred in connection with our senior note issuance and credit facility commitment increase. Net cash provided by financing activities of \$629.2 million for the three months ended March 31, 2011 was mainly the result of receiving \$659.4 million of net proceeds from the issuance and sale of an aggregate 10,080,000 shares of our common stock in March 2011, partially offset by net repayments of \$30.0 million on our credit facility.

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

Based on our planned production growth and 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 credit facility, but we may also issue debt or equity securities or sell

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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.

Revolving Credit Facility

We have a credit facility with aggregate lender commitments totaling \$1.25 billion and a current borrowing base of \$2.25 billion, 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. In January 2012, 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. 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 \$176.0 million of outstanding borrowings on our credit facility at March 31, 2012 and \$358.0 million outstanding at December 31, 2011. As of March 31, 2012, we had approximately \$1.1 billion of borrowing availability under our credit facility (after considering outstanding borrowings and letters of credit). As of April 27, 2012, we had \$317.0 million of outstanding borrowings and approximately \$929 million of borrowing availability under our credit facility.

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 facility 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 facility 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 credit facility plus our note payable and senior note obligations, divided by total EBITDAX for the most recent four quarters. We were in compliance with these covenants at March 31, 2012 and expect to maintain compliance for at least the next 12 months. A violation of these covenants 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, if any, to be due and payable. If we had any outstanding borrowings under our credit facility and such indebtedness were to be accelerated, our assets may not be sufficient to repay in full such indebtedness. 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.

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.

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Issuance of Long-Term Debt

On March 8, 2012, we issued \$800 million of 5% Senior Notes due 2022 (the 2022 Notes) and received net proceeds of approximately \$787.0 million after deducting the initial purchasers' fees. The net proceeds were used to repay a portion of the borrowings then outstanding, \$788 million, under our credit facility.

Our 8 1/4% Senior Notes due 2019 (the 2019 Notes), 7 3/8% Senior Notes due 2020 (the 2020 Notes), 7 1/8% Senior Notes due 2021 (the 2021 Notes), and the 2022 Notes (collectively, the Notes) will mature on October 1, 2019, October 1, 2020, April 1, 2021, and September 15, 2022, respectively. Interest on the 2019 Notes, 2020 Notes, and 2021 Notes is payable semi-annually on April 1 and October 1 of each year. Interest on the 2022 Notes is payable semi-annually on March 15 and September 15 of each year, commencing on September 15, 2012. We have the option to redeem all or a portion of the 2019 Notes, 2020 Notes, 2021 Notes, and 2022 Notes at any time on or after October 1, 2014, October 1, 2015, April 1, 2016, and March 15, 2017, respectively, at the redemption prices specified in the Notes' respective indentures (together, the Indentures) plus accrued and unpaid interest. We may also redeem the Notes, in whole or in part, at the make-whole redemption prices specified in the Indentures plus accrued and unpaid interest at any time prior to October 1, 2014, October 1, 2015, April 1, 2016, and March 15, 2017 for the 2019 Notes, 2020 Notes, 2021 Notes, and 2022 Notes, respectively. In addition, we may redeem up to 35% of the 2019 Notes, 2020 Notes, 2021 Notes, and 2022 Notes prior to October 1, 2012, October 1, 2013, April 1, 2014, and March 15, 2015, respectively, under certain circumstances with the net cash proceeds from certain equity offerings. Currently, we have no plans or intentions of exercising an early redemption option on the Notes. The Notes are not subject to any mandatory redemption or sinking fund requirements.

The Indentures contain certain restrictions on our ability to incur additional debt, pay dividends on common stock, make certain investments, create certain liens on assets, engage in certain transactions with affiliates, transfer or sell certain assets, consolidate or merge, or sell substantially all of our assets. These covenants are subject to a number of important exceptions and qualifications. We were in compliance with these covenants as of March 31, 2012 and expect to maintain compliance for at least the next 12 months. We do not believe the restrictive covenants will materially limit our ability to undertake additional debt or equity financing. One of our subsidiaries, Banner Pipeline Company, L.L.C., which currently has no independent assets or operations, fully and unconditionally guarantees the Notes. Our other subsidiary, the value of whose assets and operations are minor, does not guarantee the Notes.

Note payable

In February 2012, we borrowed \$22 million under a 10-year amortizing term loan secured by our corporate office building in Oklahoma City, Oklahoma. The loan bears interest at a fixed rate of 3.14% per annum. Principal and interest are payable monthly through the loan's maturity date of February 26, 2022.

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 derivative contracts are settled based upon reported settlement prices on commodity exchanges, with crude oil derivative settlements based on NYMEX West Texas Intermediate pricing or Inter-Continental Exchange pricing for Brent crude oil and natural gas derivative settlements based on NYMEX Henry Hub pricing.

We have hedged a significant portion of our forecasted production through 2014. Please see *Note 4. Derivative Instruments* in *Notes to Unaudited Condensed Consolidated Financial Statements* for further discussion of the accounting applicable to our derivative instruments, a summary of open contracts at March 31, 2012 and the estimated fair value of those contracts as of that date.

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 first three months of 2012, we participated in the completion of 154 gross (70.3 net) wells and invested a total of \$1,045.1 million in our capital program (including \$2.6 million of seismic costs and excluding \$37.4 million of capital costs associated with reduced accruals for capital expenditures). Our 2012 first quarter capital expenditures include an unbudgeted acquisition of producing and undeveloped properties in the Bakken play of North Dakota in February 2012 for \$276 million, including \$51.7 million allocated to producing properties. Our 2012 first quarter capital expenditures were allocated as follows:

	Amount in millions
Exploration and development drilling	\$ 676.9
Land costs	287.7
Capital facilities, workovers and re-completions	10.4
Buildings, vehicles, computers and other equipment	9.8
Seismic	2.6
Acquisitions of producing properties	57.7
Total	\$ 1,045.1

Our 2012 capital program focuses primarily on increased development in the North Dakota Bakken field and liquids-rich portions of the Anadarko Woodford play in western Oklahoma. Our 2012 capital expenditures through March 31, 2012 are ahead of plan. During the 2012 first quarter, we achieved improved drilling times for new wells in the Bakken field partly due to mild winter weather, which allowed us to drill more wells per operated drilling rig than planned. This resulted in improved cash flows and allowed us to accelerate our capital program at a faster pace than planned for the first quarter of the year. Further, we have been able to achieve higher average working interests in operated and non-operated properties than planned, resulting in increased capital expenditures during the first quarter. In addition, completed well costs on operated and non-operated properties are trending higher than planned partly due to inflationary pressure on the cost of oilfield services and equipment. Given these factors and resulting success of our drilling program through the first three months of the year, our Board of Directors increased our 2012 capital expenditures budget to \$2.3 billion, excluding property acquisitions. Our previous 2012 capital expenditures budget was \$1.75 billion. The revised budget reflects a \$500 million increase in planned exploratory and development drilling costs and a \$50 million increase in planned land costs. A significant majority of the additional costs will be focused on increased development in the North Dakota Bakken field. Our revised 2012 budget is expected to be allocated as follows:

	Amount in millions
Exploration and development drilling	\$ 2,040
Land costs	144
Capital facilities, workovers and re-completions	90
Seismic	20
Buildings, vehicles, computers and other equipment	6
Total	\$ 2,300

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 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. We expect to continue participating as a buyer of properties when and if we have the ability to increase our position in strategic plays at favorable terms.

Commitments

As of March 31, 2012, we had drilling rig contracts with various terms extending through August 2014. These contracts were entered into in the ordinary 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 condensed consolidated balance sheets. Future drilling commitments as of March 31, 2012 total approximately \$189 million, of which \$138 million is expected to be incurred in the remainder of 2012, \$45 million in 2013, and \$6 million in 2014. We expect to continue to enter into additional drilling rig contracts to help mitigate the risk of experiencing equipment shortages and

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rising costs that could delay our drilling projects or cause us to incur expenditures not provided for in our capital budget.

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 have been provided. Future commitments remaining at March 31, 2012 amount to approximately \$33 million, of which \$17 million is expected to be incurred in the remainder of 2012 and \$16 million in 2013. Since the inception of this agreement, we have been using the services more than the minimum number of days each quarter. 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 \$4 million as of March 31, 2012. The commitments under these arrangements are not recorded in the accompanying condensed consolidated balance sheets.

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We have a five-year firm transportation commitment, beginning in August 2011, to guarantee pipeline access 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 commitments require us to pay escalating per-barrel transportation charges totaling approximately \$7 million annually through August 2016 regardless of the amount of pipeline capacity used. Additionally, we have entered into firm transportation commitments to guarantee capacity on rail transportation facilities. The rail commitments have various terms ranging from three months to four years that extend through December 2015 and require us to pay varying per-barrel transportation charges on volumes ranging from 1,000 to 10,000 barrels of crude oil per day. Future commitments remaining as of March 31, 2012 under the rail transportation arrangements amount to approximately \$77 million, of which \$25 million is expected to be incurred in the remainder of 2012, \$35 million in 2013, \$10 million in 2014, and \$7 million in 2015. These pipeline and rail transportation commitments are for crude oil production in the Bakken field where we allocate a significant portion of our capital expenditures. The commitments under these arrangements are not recorded in the accompanying condensed consolidated balance sheets.

We are not committed under any existing contracts to deliver fixed and determinable quantities of crude oil or natural gas in the future.

We believe our cash flows from operations, our remaining cash balance, and amounts available under our credit facility will be sufficient to satisfy the above commitments.

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 the second half of 2012. We currently estimate we may incur approximately \$15 million to \$25 million of costs in connection with our relocation, with the majority of the 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. During the three months ended March 31, 2012, we recognized approximately \$1.7 million of costs associated with our relocation efforts, which are included in the caption General and administrative expenses in the unaudited condensed consolidated statements of operations. Cumulative relocation costs recognized through March 31, 2012 totaled approximately \$5 million.

Potential Issuance of Common Stock in Conjunction with Proposed Acquisition

On March 27, 2012, we entered into an agreement to purchase the right, title and interest in and to certain crude oil and natural gas properties of Wheatland Oil Inc. (Wheatland) in which we also own an interest. Wheatland is an independent exploration and production company that participates in several of our crude oil and natural gas properties located in the states of North Dakota, Montana, Oklahoma and Mississippi. Wheatland's assets included in the transaction comprise approximately 37,900 net acres in the Bakken play of North Dakota and Montana and interests in producing properties with production of approximately 2,500 net barrels of oil equivalent per day. Harold G. Hamm indirectly and Jeffrey B. Hume own 75% and 25%, respectively, of Wheatland. Mr. Hamm, our Chief Executive Officer, Chairman of the Board and principal shareholder, is the trustee and sole beneficiary of a trust that owns his shares of Wheatland. Mr. Hume is our President and Chief Operating Officer.

The transaction is subject to shareholder approval and had not been consummated at March 31, 2012. We are seeking a shareholder vote on the proposed transaction as required under New York Stock Exchange rules and the terms of the purchase and sale agreement. The purchase and sale agreement requires us to obtain approval of a majority of the issued and outstanding shares held by shareholders other than members of our Board of Directors, our executive officers, Mr. Hamm and his affiliates, and Mr. Hume and his affiliates. If the transaction is not approved by such shareholders, the purchase and sale agreement will terminate without the payment of fees by either party.

The proposed purchase price for the assets is \$340 million, subject to customary purchase price adjustments. The adjusted purchase price will be paid in shares of our common stock, par value \$0.01 per share, and is anticipated to result in the issuance of between 3.90 million and 4.25 million shares depending on the daily sales prices of the Company's common stock for a period prior to the closing of the transaction. The actual number of shares of common stock to be issued will not be known until the closing of the transaction and the determination of any purchase price adjustments. The adjusted purchase price could be more or less than \$340 million. The issuance of equity securities in conjunction with the proposed transaction could have a dilutive effect on the value of our common stock.

Table of Contents**Critical Accounting Policies**

There has been no change in our critical accounting policies from those disclosed in our Form 10-K for the year ended December 31, 2011.

Recent Accounting Pronouncements Not Yet Adopted

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.

Non-GAAP Financial Measures

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 these 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 also be used by investors to measure our ability to meet future debt service requirements, if any. Our credit facility requires that we maintain a total 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 note payable and senior note obligations, divided by total EBITDAX for the most recent four quarters. We were in compliance with this covenant at March 31, 2012. 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, if any, to be due and payable. If we had any outstanding borrowings under our credit facility and such indebtedness 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.

<i>in thousands</i>	Three months ended March 31,	
	2012	2011
Net income (loss)	\$ 69,094	\$ (137,201)
Interest expense	24,278	18,971
Provision (benefit) for income taxes	43,000	(84,154)
Depreciation, depletion, amortization and accretion	149,455	75,650
Property impairments	29,907	20,848
Exploration expenses	4,151	6,812
Unrealized losses on derivatives	129,132	364,087

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Non-cash equity compensation	5,515	3,642
EBITDAX	\$ 454,532	\$ 268,655

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ITEM 3. Quantitative and Qualitative Disclosures About Market Risk

General. 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 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 prices. Based on our average daily production for the three months ended March 31, 2012, and excluding any effect of our derivative instruments in place, our annual revenue would increase or decrease by approximately \$219 million for each \$10.00 per barrel change in crude oil prices and \$56 million for each \$1.00 per Mcf change in natural gas prices.

To 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 derivative contract index 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 three months ended March 31, 2012, we realized a net loss on crude oil and natural gas derivatives of \$39.9 million and reported an unrealized non-cash mark-to-market loss on derivatives of \$129.1 million. The fair value of our derivative instruments at March 31, 2012 was a net liability of \$293.4 million. An assumed increase in the forward commodity prices used in the March 31, 2012 valuation of our derivative instruments of \$10.00 per barrel for crude oil and \$1.00 per MMBtu for natural gas would change our derivative valuation to a net liability of approximately \$654 million at March 31, 2012. 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 \$57 million at March 31, 2012.

Throughout 2011 and during the first three months of 2012, we have entered into a number of derivative instruments, including fixed price swaps and zero-cost collars, to reduce the uncertainty of future cash flows in order to underpin our capital expenditures and our drilling program through 2014. Changes in commodity futures price strips during the three months ended March 31, 2012 had an overall negative impact on the fair value of our derivative instruments, which resulted in the recognition of a \$129.1 million unrealized mark-to-market loss on derivative instruments for the first three months of 2012. The unrealized mark-to-market loss relates to derivative instruments with various terms that are scheduled to be realized over the period from April 2012 through December 2014. Over this period, actual realized derivative settlements may differ significantly, either positively or negatively, from the unrealized mark-to-market valuation at March 31, 2012.

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 (\$387.4 million in receivables at March 31, 2012), our joint interest receivables (\$410.0 million at March 31, 2012), and counterparty credit risk associated with our derivative instrument receivables (\$17.5 million at March 31, 2012).

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 \$43.8 million at March 31, 2012, 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.

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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, our derivative contracts are with parties that are lenders (or affiliates of lenders) under our credit facility.

Interest Rate Risk. Our exposure to changes in interest rates relates primarily to any variable-rate borrowings we may have outstanding from time to time under our 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 \$317.0 million of outstanding borrowings under our credit facility at April 27, 2012. The impact of a 1% increase in interest rates on this amount of debt would result in increased interest expense of approximately \$3.2 million per year and a \$2.0 million decrease in net income per year. Our credit facility matures on July 1, 2015 and the weighted-average interest rate on outstanding borrowings at April 27, 2012 was 2.0%.

ITEM 4. Controls and Procedures

Evaluation of Disclosure Controls and Procedures

Based on management's evaluation, under the supervision and with the participation of our principal executive officer and principal financial officer, as of the end of the period covered by this report, our principal executive officer and principal financial officer have concluded that our disclosure controls and procedures (which are defined in Rules 13a-15(e) and 15d-15(e) of the Securities Exchange Act of 1934, as amended (the Exchange Act)) were effective as of March 31, 2012. Disclosure controls and procedures include, without limitation, controls and procedures designed to provide reasonable assurance that the information required to be disclosed by us in the reports we file or submit under the Exchange Act is accumulated and communicated to our management, including our Chief Executive Officer and Chief Financial Officer, to allow timely decisions regarding required disclosures and is recorded, processed, summarized and reported within the time period in the rules and forms of the SEC.

Changes in Internal Control over Financial Reporting

During the quarter ended March 31, 2012, there were no changes in our internal control over financial reporting (as such term is defined in Rules 13a-15(f) and 15d-15(f) under the Exchange Act) that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

Inherent Limitations on Controls and Procedures

A control system, no matter how well conceived and operated, can provide only reasonable, not absolute, assurance that the objectives of the control system are met. Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risks that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate. Accordingly, even an effective system of internal control will provide only reasonable assurance that the objectives of the internal control system are met.

Table of Contents**PART II. Other Information****ITEM 1. Legal Proceedings**

During the three months ended March 31, 2012, there have been no material changes with respect to the legal proceedings previously disclosed in our 2011 Form 10-K that was filed with the SEC on February 24, 2012. See *Note 7. Commitments and Contingencies in Notes to Unaudited Condensed Consolidated Financial Statements* of this Form 10-Q.

ITEM 1A. Risk Factors

There have been no material changes in our risk factors from those disclosed in our 2011 Form 10-K.

In addition to the information set forth in this Form 10-Q, you should carefully consider the risk factors discussed in *Part I, Item 1A. Risk Factors* in our 2011 Form 10-K, which could materially affect our business, financial condition or future results. The risks described in this Form 10-Q and in our 2011 Form 10-K are not the only risks facing our Company. Additional risks and uncertainties not currently known to us or that we currently deem to be immaterial also may materially adversely affect our business, financial condition or future results.

ITEM 2. Unregistered Sales of Equity Securities and Use of Proceeds

(a) Not applicable.

(b) Not applicable.

(c) Purchases of Equity Securities by the Issuer and Affiliated Purchasers.

The following table provides information about purchases of equity securities that are registered by us pursuant to Section 12 of the Exchange Act during the quarter ended March 31, 2012:

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⁾
January 1, 2012 to January 31, 2012	1,235	\$ 69.86		
February 1, 2012 to February 29, 2012	6,667	\$ 84.45		
March 1, 2012 to March 31, 2012	34,590	\$ 89.46		
Total	42,492	\$ 88.11		

- (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.

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- (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 vesting of restrictions on shares under the 2005 Plan. With respect to the 2000 Plan, all options issued under that plan have been exercised or have expired at March 31, 2012.

ITEM 3. Defaults Upon Senior Securities

Not applicable.

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ITEM 4. Mine Safety Disclosures

Not applicable.

ITEM 5. Other Information

Not applicable.

ITEM 6. Exhibits

The exhibits required to be filed pursuant to Item 601 of Regulation S-K are set forth in the Index to Exhibits accompanying this report and are incorporated herein by reference.

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SIGNATURE

Pursuant to the requirements of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned thereunto duly authorized.

CONTINENTAL RESOURCES, INC.

Date: May 3, 2012

By: /s/ John D. Hart
John D. Hart
Sr. Vice President, Chief Financial Officer and Treasurer (Duly
Authorized Officer and Principal Financial Officer)

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Index to Exhibits

2.1	Reorganization and Purchase and Sale Agreement dated as of March 27, 2012 among Continental Resources, Inc., Wheatland Oil Inc. and the shareholders of Wheatland Oil Inc. filed as Exhibit 2.1 to the Company's Current Report on Form 8-K (Commission File No. 001-32886) filed April 2, 2012 and incorporated herein by reference.
3.1	Third Amended and Restated Certificate of Incorporation of Continental Resources, Inc. filed as Exhibit 3.1 to the Company's 2011 Form 10-K (Commission File No. 001-32886) filed February 24, 2012 and incorporated herein by reference.
3.2	Second Amended and Restated Bylaws of Continental Resources, Inc. filed as Exhibit 3.2 to the Company's 2011 Form 10-K (Commission File No. 001-32886) filed February 24, 2012 and incorporated herein by reference.
4.1	Indenture dated as of March 8, 2012 among Continental Resources, Inc., Banner Pipeline Company, L.L.C. and Wilmington Trust, National Association, as trustee, filed as Exhibit 4.1 to the Company's Current Report on Form 8-K (Commission File No. 001-32886) filed March 8, 2012 and incorporated herein by reference.
4.2	Registration Rights Agreement dated as of March 8, 2012 among Continental Resources, Inc., Banner Pipeline Company, L.L.C. and Merrill Lynch, Pierce, Fenner & Smith Incorporated as the representative of the several initial purchasers, filed as Exhibit 4.2 to the Company's Current Report on Form 8-K (Commission File No. 001-32886) filed March 8, 2012 and incorporated herein by reference.
10.1	Purchase Agreement dated as of March 5, 2012 among Continental Resources, Inc., Banner Pipeline Company, L.L.C. and Merrill Lynch, Pierce, Fenner & Smith Incorporated as the representative of the several initial purchasers, filed as Exhibit 10.1 to the Company's Current Report on Form 8-K (Commission File No. 001-32886) filed March 6, 2012 and incorporated herein by reference.
31.1*	Certification of the Company's Chief Executive Officer Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002 (15 U.S.C. Section 7241).
31.2*	Certification of the Company's Chief Financial Officer Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002 (15 U.S.C. Section 7241).
32**	Certification of the Company's Chief Executive Officer and Chief Financial Officer Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002 (18 U.S.C. Section 1350).
101.INS**	XBRL Instance Document
101.SCH**	XBRL Taxonomy Extension Schema Document
101.CAL**	XBRL Taxonomy Extension Calculation Linkbase Document
101.DEF**	XBRL Taxonomy Extension Definition Linkbase Document
101.LAB**	XBRL Taxonomy Extension Label Linkbase Document
101.PRE**	XBRL Taxonomy Extension Presentation Linkbase Document

* Filed herewith

** Furnished herewith