CONTINENTAL RESOURCES INC
Form 10-Q
August 09, 2012
Table of Contents

UNITED STATES

SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

FORM 10-Q

(Mark One)

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

For the quarterly period ended June 30, 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)

Oklahoma	**73-0767549**
(State or other jurisdiction of incorporation or organization)	**(I.R.S. Employer Identification No.)**
20 N. Broadway, Oklahoma City, Oklahoma	**73102**
(Address of principal executive offices)	**(Zip Code)**

(405) 234-9000

(Registrant s telephone number, including area code)

Not Applicable

(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 x No ¨

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

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

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

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

181,134,919 shares of our $0.01 par value common stock were outstanding on August 1, 2012.

Table of Contents

When we refer to us, we, our, Company, or Continental we are describing Continental Resources, Inc. and our subsidiaries.

Glossary of Crude Oil and Natural Gas Terms

The terms included 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.

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.

Table of Contents

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 renewal is reasonably certain.

proved developed reserves Proved 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.

Table of Contents

Cautionary Statement Regarding Forward-Looking Statements

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

	June 30, 2012 (Unaudited)	December 31, 2011
	In thousands, except par values and share data	
Assets		
Current assets:		
Cash and cash equivalents	$ 29,137	$ 53,544
Receivables:		
Crude oil and natural gas sales	364,437	366,441
Affiliated parties	20,450	31,108
Joint interest and other, net	375,278	379,991
Derivative assets	79,584	6,669
Inventories	51,276	41,270
Deferred and prepaid taxes	2,234	47,658
Prepaid expenses and other	8,180	9,692
Total current assets	930,576	936,373
Net property and equipment, based on successful efforts method of accounting	6,178,663	4,681,733
Net debt issuance costs and other	39,294	24,355
Noncurrent derivative assets	105,779	3,625
Total assets	$ 7,254,312	$ 5,646,086
Liabilities and shareholders equity		
Current liabilities:		
Accounts payable trade	$ 665,793	$ 642,889
Revenues and royalties payable	226,505	222,027
Payables to affiliated parties	9,223	9,939
Accrued liabilities and other	176,745	117,674
Derivative liabilities		116,985
Current portion of asset retirement obligations	1,805	2,287
Current portion of long-term debt	1,919	
Total current liabilities	1,081,990	1,111,801
Long-term debt, net of current portion	2,252,918	1,254,301
Other noncurrent liabilities:		
Deferred income tax liabilities	1,071,536	850,282
Asset retirement obligations, net of current portion	52,959	60,338
Noncurrent derivative liabilities		57,598
Other noncurrent liabilities	3,412	3,640
Total other noncurrent liabilities	1,127,907	971,858
Commitments and contingencies (Note 7)		
Shareholders equity:		

Preferred stock, $0.01 par value; 25,000,000 shares authorized; no shares issued and outstanding		
Common stock, $0.01 par value; 500,000,000 shares authorized; 181,155,020 shares issued and outstanding at June 30, 2012; 180,871,688 shares issued and outstanding at December 31, 2011	1,812	1,809
Additional paid-in capital	1,119,284	1,110,694
Retained earnings	1,670,401	1,195,623
Total shareholders equity	2,791,497	2,308,126
Total liabilities and shareholders equity	$ 7,254,312	$ 5,646,086

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

1

Table of Contents

Continental Resources, Inc. and Subsidiaries

Unaudited Condensed Consolidated Statements of Income

	Three months ended June 30, 2012	Three months ended June 30, 2011	Six months ended June 30, 2012	Six months ended June 30, 2011
	In thousands, except per share data			
Revenues				
Crude oil and natural gas sales	$ 511,192	$ 378,388	$ 1,046,504	$ 695,128
Crude oil and natural gas sales to affiliates	12,201	10,396	29,147	20,123
Gain (loss) on derivative instruments, net	471,728	204,453	302,671	(164,850)
Crude oil and natural gas service operations	9,598	9,655	21,497	16,281
Total revenues	1,004,719	602,892	1,399,819	566,682
Operating costs and expenses				
Production expenses	43,479	31,444	83,495	59,842
Production and other expenses to affiliates	1,427	917	2,496	1,789
Production taxes and other expenses	48,077	33,491	97,807	61,053
Exploration expenses	8,702	5,034	12,853	11,846
Crude oil and natural gas service operations	7,255	8,064	17,097	13,515
Depreciation, depletion, amortization and accretion	161,018	83,501	310,473	159,151
Property impairments	35,871	19,242	65,778	40,090
General and administrative expenses	29,813	17,209	54,779	33,556
Gain on sale of assets, net	(17,397)	(318)	(67,024)	(15,575)
Total operating costs and expenses	318,245	198,584	577,754	365,267
Income from operations	686,474	404,308	822,065	201,415
Other income (expense):				
Interest expense	(31,691)	(18,785)	(55,969)	(37,756)
Other	789	1,022	1,570	1,531
	(30,902)	(17,763)	(54,399)	(36,225)
Income before income taxes	655,572	386,545	767,666	165,190
Provision for income taxes	249,888	147,351	292,888	63,197
Net income	$ 405,684	$ 239,194	$ 474,778	$ 101,993
Basic net income per share	$ 2.26	$ 1.33	$ 2.64	$ 0.58
Diluted net income per share	$ 2.25	$ 1.33	$ 2.63	$ 0.58

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

2

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
			In thousands, except share data		
Balance at December 31, 2011	180,871,688	$ 1,809	$ 1,110,694	$ 1,195,623	$ 2,308,126
Net income (unaudited)				474,778	474,778
Stock-based compensation (unaudited)			13,624		13,624
Stock options:					
Exercised (unaudited)	86,500		60		60
Repurchased and canceled (unaudited)	(32,984)		(2,951)		(2,951)
Restricted stock:					
Issued (unaudited)	266,888	3			3
Repurchased and canceled (unaudited)	(28,095)		(2,143)		(2,143)
Forfeited (unaudited)	(8,977)				
Balance at June 30, 2012	181,155,020	$ 1,812	$ 1,119,284	$ 1,670,401	$ 2,791,497

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

	Six months ended June 30, 2012	2011
Cash flows from operating activities	*In thousands*	
Net income	$ 474,778	$ 101,993
Adjustments to reconcile net income to net cash provided by operating activities:		
Depreciation, depletion, amortization and accretion	314,367	161,184
Property impairments	65,778	40,090
Change in fair value of derivatives	(349,652)	132,756
Stock-based compensation	13,305	7,497
Provision for deferred income taxes	290,738	62,237
Dry hole costs	98	3,370
Gain on sale of assets, net	(67,024)	(15,575)
Other, net	2,275	1,799
Changes in assets and liabilities:		
Accounts receivable	18,375	(129,701)
Inventories	(10,212)	(12,478)
Prepaid expenses and other	2,952	(1,665)
Accounts payable trade	(21,661)	16,712
Revenues and royalties payable	4,477	43,974
Accrued liabilities and other	32,241	16,779
Other noncurrent assets and liabilities	(5)	(6)
Net cash provided by operating activities	770,830	428,966
Cash flows from investing activities		
Exploration and development	(1,778,808)	(797,414)
Purchase of producing crude oil and natural gas properties	(63,263)	(149)
Purchase of other property and equipment	(32,230)	(28,837)
Proceeds from sale of assets	100,809	22,784
Net cash used in investing activities	(1,773,492)	(803,616)
Cash flows from financing activities		
Revolving credit facility borrowings	1,239,000	135,000
Repayment of revolving credit facility	(1,060,000)	(165,000)
Proceeds from issuance of Senior Notes	787,000	
Proceeds from other debt	22,000	
Repayment of other debt	(628)	
Proceeds from issuance of common stock		659,736
Debt issuance costs	(4,083)	(37)
Equity issuance costs		(368)
Repurchase of equity grants	(5,094)	(1,198)
Exercise of stock options	60	9
Net cash provided by financing activities	978,255	628,142
Net change in cash and cash equivalents	(24,407)	253,492
Cash and cash equivalents at beginning of period	53,544	7,916
Cash and cash equivalents at end of period	$ 29,137	$ 261,408

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

4

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 approximately 75% of the Company s crude oil and natural gas production for the six months ended June 30, 2012. The Company has focused its operations on the exploration and development of crude oil since the 1980s. For the six months ended June 30, 2012, crude oil accounted for approximately 69% of the Company s crude oil and natural gas production and approximately 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 June 30, 2012 and for the three and six month periods ended June 30, 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 condensed consolidated 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:

In thousands	**June 30, 2012**	**December 31, 2011**
Tubular goods and equipment	$ 14,707	$ 15,665
Crude oil	36,569	25,605

Total	$ 51,276	$ 41,270

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:

Continental Resources, Inc. and Subsidiaries

Notes to Unaudited Condensed Consolidated Financial Statements

MBbl	June 30, 2012	December 31, 2011
Crude oil line fill requirements	388	283
Temporarily stored crude oil	348	152
Total	736	435

Earnings per share

Basic net income per share is computed by dividing net income by the weighted-average number of shares outstanding for the period. Diluted net income 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 per share for the three and six months ended June 30, 2012 and 2011:

	Three months ended June 30,		Six months ended June 30,	
	2012	2011	2012	2011
	In thousands, except per share data			
Income (numerator):				
Net income - basic and diluted	$ 405,684	$ 239,194	$ 474,778	$ 101,993
Weighted average shares (denominator):				
Weighted average shares - basic	179,781	179,424	179,744	175,598
Non-vested restricted stock	554	707	541	703
Stock options		98	32	99
Weighted average shares - diluted	180,335	180,229	180,317	176,400
Net income per share:				
Basic	$ 2.26	$ 1.33	$ 2.64	$ 0.58
Diluted	$ 2.25	$ 1.33	$ 2.63	$ 0.58

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 assets and liabilities but does not result in cash receipts or payments.

	Six months ended June 30,	
	2012	2011
	In thousands	
Supplemental cash flow information:		
Cash paid for interest	$ 38,567	$ 35,658
Cash paid for income taxes	754	3,164
Cash received for income tax refunds	(72)	(116)
Non-cash investing activities:		
Increase in accrued capital expenditures	43,850	35,895
Asset retirement obligations, net	2,973	1,071

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 in the unaudited condensed consolidated statements of income under the caption Gain (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.

Table of Contents

Continental Resources, Inc. and Subsidiaries

Notes to Unaudited Condensed Consolidated Financial Statements

During the six months ended June 30, 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 (WTI) pricing or Inter-Continental Exchange (ICE) 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 June 30, 2012, the Company had outstanding derivative contracts with respect to future production as set forth in the tables below.

Crude Oil - NYMEX West Texas Intermediate		Swaps	Collars			
			Floors		Ceilings	
Period and Type of Contract	Bbls	Weighted Average Price	Range	Weighted Average Price	Range	Weighted Average Price
July 2012 - December 2012						
Swaps - WTI	3,680,000	$ 88.69				
Collars - WTI	2,680,880		$ 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	5,931,250	$ 100.04				

Crude Oil - ICE Brent		
Period and Type of Contract	Bbls	Weighted Average Price
July 2012 - December 2012		
Swaps - ICE Brent	2,116,000	$ 111.17
January 2013 - December 2013		
Swaps - ICE Brent	2,372,500	$ 109.19

Table of Contents

Continental Resources, Inc. and Subsidiaries

Notes to Unaudited Condensed Consolidated Financial Statements

Natural Gas - Henry Hub **Period and Type of Contract**	**MMBtus**	**Weighted Average Price**
July 2012 - December 2012		
Swaps - Henry Hub	11,040,000	$ 3.45
January 2013 - December 2013		
Swaps - Henry Hub	18,250,000	$ 3.76

Derivative Fair Value Gain (Loss)

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

	Three months ended June 30,		**Six months ended June 30,**	
	2012	**2011**	**2012**	**2011**
		In thousands		
Realized gain (loss) on derivatives:				
Crude oil fixed price swaps	$ (6,367)	$ (4,881)	$ (37,791)	$ (7,976)
Crude oil collars	(4,048)	(29,394)	(14,968)	(39,641)
Natural gas fixed price swaps	3,359	7,397	5,778	15,523
Total realized gain (loss) on derivatives	$ (7,056)	$ (26,878)	$ (46,981)	$ (32,094)
Unrealized gain (loss) on derivatives:				
Crude oil fixed price swaps	$ 329,545	$ 87,179	$ 248,547	$ (77,864)
Crude oil collars	158,053	147,572	99,110	(47,516)
Natural gas fixed price swaps	(8,814)	(3,420)	1,995	(7,376)
Total unrealized gain (loss) on derivatives	$ 478,784	$ 231,331	$ 349,652	$ (132,756)
Gain (loss) on derivative instruments, net	$ 471,728	$ 204,453	$ 302,671	$ (164,850)

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

		June 30, 2012			**December 31, 2011**	
In thousands	**Assets Fair Value**	**(Liabilities) Fair Value**	**Net Fair Value**	**Assets Fair Value**	**(Liabilities) Fair Value**	**Net Fair Value**
Commodity swaps and collars	$ 185,363	$	$ 185,363	$ 10,294	$ (174,583)	$ (164,289)

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.

Continental Resources, Inc. and Subsidiaries

Notes to Unaudited Condensed Consolidated Financial Statements

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 June 30, 2012 and December 31, 2011.

	Fair value measurements at June 30, 2012 using:			
Description	**Level 1**	**Level 2**	**Level 3**	**Total**
		In thousands		
Derivative assets (liabilities):				
Fixed price swaps	$	$ 147,432	$	$ 147,432
Collars		37,931		37,931
Total	$	$ 185,363	$	$ 185,363

	Fair value measurements at December 31, 2011 using:			
Description	**Level 1**	**Level 2**	**Level 3**	**Total**
		In thousands		
Derivative assets (liabilities):				
Fixed price swaps	$	$ (103,110)	$	$ (103,110)
Collars		(61,179)		(61,179)
Total	$	$ (164,289)	$	$ (164,289)

The following table sets forth a reconciliation of changes in the fair value of financial assets and liabilities classified as Level 3 in the fair value hierarchy for the indicated periods. The Company s crude oil collar contracts, which were classified as Level 3 instruments in the fair value hierarchy as of and for the six months ending June 30, 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

	In thousands
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	

Table of Contents

Continental Resources, Inc. and Subsidiaries

Notes to Unaudited Condensed Consolidated Financial Statements

Issuances	
Settlements	
Transfers into Level 3	
Transfers out of Level 3	
Balance at March 31, 2011	$ (298,506)
Total realized or unrealized gains (losses) net:	
Included in earnings	147,573
Included in other comprehensive income	
Purchases	
Sales	
Issuances	
Settlements	
Transfers into Level 3	
Transfers out of Level 3	
Balance at June 30, 2011	$ (150,933)
Unrealized losses included in earnings for the six months ended June 30, 2011 relating to derivatives held at June 30, 2011	$ (49,102)

Gains and losses included in earnings for the three and six month periods ended June 30, 2012 and 2011 attributable to the change in unrealized gains and losses relating to derivatives held at June 30, 2012 and 2011 are reported in the unaudited condensed consolidated statements of income under the caption Gain (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**
Future production	Future production estimates for each property
Forward commodity prices	Forward NYMEX swap prices through 2015 (adjusted for differentials), 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
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.

Table of Contents

Continental Resources, Inc. and Subsidiaries

Notes to Unaudited Condensed Consolidated Financial Statements

At June 30, 2012, the Company determined the carrying amounts of certain proved properties were not recoverable from future cash flows and, therefore, were impaired. Impairments of proved properties amounted to $4.3 million for the six months ended June 30, 2012, all of which was recognized in the second quarter. The impaired properties were written down to their estimated fair value totaling approximately $2.2 million. No impairment provisions were recorded for the Company s proved properties for the three or six month periods ended June 30, 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 and six months ended June 30, 2012 and 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. Individually significant unproved properties, if any, are assessed for impairment on a property-by-property basis and, if the assessment indicates an impairment, a loss is recognized by providing a valuation allowance consistent with the level at which impairment was assessed. There are currently no individually significant unproved properties that are assessed for impairment on a property-by-property basis.

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 income.

	Three months ended June 30,		Six months ended June 30,	
	2012	2011	2012	2011
	In thousands			
Proved property impairments	$ 4,332	$	$ 4,332	$
Unproved property impairments	31,539	19,242	61,446	40,090
Total	$ 35,871	$ 19,242	$ 65,778	$ 40,090

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, 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 $1.7 million and $2.9 million for the three and six months ended June 30, 2012, 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 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.

Continental Resources, Inc. and Subsidiaries

Notes to Unaudited Condensed Consolidated Financial Statements

In thousands	June 30, 2012 Carrying Amount	June 30, 2012 Fair Value	December 31, 2011 Carrying Amount	December 31, 2011 Fair Value
Debt:				
Revolving credit facility	$ 537,000	$ 537,000	$ 358,000	$ 358,000
Note payable	21,372	21,525		
8 1/4% Senior Notes due 2019	297,981	334,500	297,882	331,000
7 3/8% Senior Notes due 2020	198,484	223,167	198,419	219,000
7 1/8% Senior Notes due 2021	400,000	446,000	400,000	435,333
5% Senior Notes due 2022	800,000	812,667		
Total debt	$ 2,254,837	$ 2,374,859	$ 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 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 5% Senior Notes due 2022 (the 2022 Notes) 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:

	June 30, 2012	December 31, 2011
	In thousands	
Revolving credit facility	$ 537,000	$ 358,000
Note payable	21,372	
8 1/4% Senior Notes due 2019(1)	297,981	297,882
7 3/8% Senior Notes due 2020(2)	198,484	198,419
7 1/8% Senior Notes due 2021(3)	400,000	400,000
5% Senior Notes due 2022(3)	800,000	
Total debt	$ 2,254,837	$ 1,254,301
Less: Current portion of long-term debt	(1,919)	
Long-term debt, net of current portion	$ 2,252,918	$ 1,254,301

(1) The carrying amount is net of discounts of $2.0 million and $2.1 million at June 30, 2012 and December 31, 2011, respectively.
(2) The carrying amount is net of discounts of $1.5 million and $1.6 million at June 30, 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 $537.0 million of outstanding borrowings at June 30, 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 June 30, 2012, subject to semi-annual redetermination. At June 30, 2012 the terms of the facility allowed for the commitment level to be increased up to the lesser of the borrowing base then in effect or $2.5 billion. At June 30, 2012, borrowings under the facility bore 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. At June 30, 2012, credit facility borrowings were 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.

Continental Resources, Inc. and Subsidiaries

Notes to Unaudited Condensed Consolidated Financial Statements

The Company had approximately $708.6 million of unused commitments (after considering outstanding borrowings and letters of credit) under its credit facility at June 30, 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 at June 30, 2012. 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, non-cash gains and losses resulting from the requirements of accounting for derivatives, and non-cash equity compensation expense. EBITDAX is not a measure of net income or operating cash flows as determined by U.S. GAAP. Reconciliations of net income and operating cash flows to EBITDAX are 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 June 30, 2012.

On July 26, 2012, certain terms of the Company s credit agreement were amended. Amendments included the following, among other changes:

- Borrowing base increased from $2.25 billion to $2.75 billion;

- Aggregate credit facility commitments increased from $1.25 billion to $1.5 billion;

- Interest margins on advances were decreased by 25 basis points for all utilization levels. LIBOR margins now range from 150 to 250 basis points and reference rate margins now range from 50 to 150 basis points, depending on the percentage of the borrowing base utilized;

- Commitment fees on unused borrowing capacity were decreased from 0.50% to 0.375% when utilization of the credit facility is below 50%;

- Reduced the security requirement from 85% to 80% by value of all proved reserves and associated crude oil and natural gas properties, unless the Collateral Coverage Ratio, as defined in the amended credit agreement, is greater than or equal to 1.75 to 1.0, in which case the 80% security requirement will not apply; and

- Total Funded Debt to EBITDAX covenant ratio requirement was increased from 3.75:1.0 to 4.0:1.0.

Senior Notes

On March 8, 2012, the Company issued $800 million of 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 under the Company s credit facility.

The following table summarizes the maturity dates, semi-annual interest payment dates, and optional redemption periods related to the Company s outstanding Senior Note obligations.

	2019 Notes	2020 Notes	2021 Notes	2022 Notes
Maturity date	October 1, 2019	October 1, 2020	April 1, 2021	September 15, 2022
Semi-annual interest payment dates	April 1, October 1	April 1, October 1	April 1, October 1	March 15, Sept. 15
Decreasing call premium redemption period (1)	October 1, 2014	October 1, 2015	April 1, 2016	March 15, 2017
Make-whole redemption period (2)	October 1, 2014	October 1, 2015	April 1, 2016	March 15, 2017
Redemption using equity offering proceeds (3)	October 1, 2012	October 1, 2013	April 1, 2014	March 15, 2015

(1) On or after these dates, the Company has the option to redeem all or a portion of its Senior Notes at the decreasing redemption prices specified in the respective Senior Note indentures (together, the Indentures) plus any accrued and unpaid interest to the date of redemption.

(2) At any time prior to these dates, the Company has the option to redeem all or a portion of its Senior Notes at the make-whole redemption prices specified in the Indentures plus any accrued and unpaid interest to the date of redemption.

(3) At any time prior to these dates, the Company may redeem up to 35% of the principal amount of its Senior Notes under certain circumstances with the net cash proceeds from one or more equity offerings at the redemption prices specified in the Indentures plus any accrued and unpaid interest to the date of redemption.

The Company s Senior 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 June 30, 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 Senior Notes. The Company s other subsidiary, the value of whose assets and operations are minor, does not guarantee the Senior Notes.

Continental Resources, Inc. and Subsidiaries

Notes to Unaudited Condensed Consolidated Financial Statements

Note payable

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 $1.9 million is reflected as a current liability under the caption Current portion of long-term debt in the condensed consolidated balance sheets as of June 30, 2012.

Note 7. Commitments and Contingencies

Drilling commitments As of June 30, 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 June 30, 2012 total approximately $184 million, of which $102 million is expected to be incurred in the remainder of 2012, $67 million in 2013, and $15 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 June 30, 2012 amount to approximately $28 million, of which $11 million is expected to be incurred in the remainder of 2012 and $17 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 $2 million as of June 30, 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 extending through December 2015 and require the Company to pay varying per-barrel transportation charges on volumes ranging from 2,500 to 10,000 barrels of crude oil per day. Future commitments remaining as of June 30, 2012 under the rail transportation arrangements amount to approximately $69 million, of which $17 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 is ongoing and information and documents continue to be 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. Two lawsuits have been filed against the Company and certain members of its management and Board of Directors related to the proposed acquisition of crude oil and natural gas properties of Wheatland Oil Inc. See *Part II, Item 1. Legal Proceedings* for further discussion. 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 June 30, 2012 and December 31, 2011, the Company has recorded a liability in the condensed consolidated balance sheets under the caption Other noncurrent liabilities of $2.4 million and $2.6 million, respectively, for various matters, none of which are believed to be individually significant.

Continental Resources, Inc. and Subsidiaries

Notes to Unaudited Condensed Consolidated Financial Statements

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 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 in addition to matching 100% of eligible employees contributions up to 4% of eligible compensation. Expenses associated with the plan amounted to $2.1 million and $1.5 million for the six months ended June 30, 2012 and June 30, 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 $3.4 million and $2.7 million at June 30, 2012 and December 31, 2011, respectively.

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 income, is reflected in the table below for the periods presented.

	Three months ended June 30,		Six months ended June 30,	
	2012	2011	2012	2011
	In thousands			
Non-cash equity compensation	$ 7,790	$ 3,855	$ 13,305	$ 7,497

Stock Options

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 had been exercised or expired and there has been no activity subsequent to that date.

The Company s stock option activity under the 2000 Plan for the six months ended June 30, 2012 is presented below:

	Outstanding		Exercisable	
	Number of stock options	Weighted average exercise price	Number of stock options	Weighted average exercise 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 June 30, 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 six months ended June 30, 2012 was $7.6 million, all of which relates to stock options exercised during the three months ended March 31, 2012.

Continental Resources, Inc. and Subsidiaries

Notes to Unaudited Condensed Consolidated Financial Statements

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 June 30, 2012, the Company had 2,401,471 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 six months ended June 30, 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	266,888	78.08
Vested	(105,472)	43.72
Forfeited	(8,977)	58.38
Non-vested restricted shares at June 30, 2012	1,350,783	$ 54.80

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 six months ended June 30, 2012 at the vesting date was $8.0 million. As of June 30, 2012, there was $46.1 million of unrecognized compensation expense related to non-vested restricted stock. This expense is expected to be recognized over a weighted average period of 1.4 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 which $51.7 million was allocated to producing properties. 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 June 2012, the Company assigned certain non-strategic leaseholds and producing properties located in Oklahoma to a third party for cash proceeds of $15.9 million and recognized a pre-tax gain on the transaction of $15.9 million, which included the effect of removing $0.6 million of asset retirement obligations for the disposed properties previously recognized by the Company that were assumed by the buyer. The disposed properties represented an immaterial portion of the Company s total proved reserves and production.

In February 2012, the Company assigned certain non-strategic leaseholds and producing properties located in 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 included 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 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 the above transactions are included in Gain on sale of assets, net in the unaudited condensed consolidated statements of income.

Table of Contents

Continental Resources, Inc. and Subsidiaries

Notes to Unaudited Condensed Consolidated Financial Statements

Note 10. Proposed Property Transaction with Related Party

On March 27, 2012, the Company entered into a Reorganization and Purchase and Sale Agreement (the Agreement) with Wheatland Oil Inc. (Wheatland), and the shareholders of Wheatland. Wheatland is owned 75% by the Revocable Inter Vivos Trust of Harold G. Hamm, a trust of which Harold G. Hamm, our Chief Executive Officer, Chairman of the Board and principal shareholder is the trustee and sole beneficiary, and 25% by our Vice Chairman of Strategic Growth Initiatives, Jeffrey B. Hume. The Company s Board of Directors formed a special committee comprised of independent board members to protect the interests of the Company and its minority shareholders in connection with the Agreement. The special committee negotiated the Agreement with Wheatland and its shareholders.

The Agreement provides for the acquisition by the Company of all of Wheatland s right, title and interest in and to certain crude oil and natural gas properties and related assets, in which the Company also owns an interest, in the states of Mississippi, Montana, North Dakota and Oklahoma and the assumption of certain liabilities related thereto. Wheatland s assets included in the transaction are primarily comprised of approximately 37,900 net acres in the North Dakota and Montana Bakken play and interests in producing properties with production of approximately 2,500 net barrels of oil equivalent per day as of December 31, 2011.

The Company is holding a shareholder vote on the proposed transaction as required by New York Stock Exchange rules and the terms of the Agreement. The New York Stock Exchange Listed Company Manual requires the approval by a majority of votes cast at the special meeting, provided the total vote cast represents over 50% in interest of all securities entitled to vote on the matter. Oklahoma state law requires any proposal submitted to the Company s shareholders be approved by a majority of the shares present in person or represented by proxy and entitled to vote on the matter. In addition, the Agreement requires the Company to obtain approval of a majority of the issued and outstanding shares held by shareholders other than members of the Company s Board of Directors, its executive officers, Mr. Hamm and his affiliates, and Mr. Hume and his affiliates (referred to herein as the Unaffiliated Vote Requirement). If the issuance of shares pursuant to the Agreement does not receive the required approvals, the Agreement will terminate without the payment of fees by any party. A shareholder meeting will be held on August 10, 2012 for the purpose of voting whether to approve the issuance of shares pursuant to the Agreement.

The purchase price for the assets consists of $340 million (the Unadjusted Purchase Price), subject to customary purchase price adjustments associated with transactions of this nature in the oil and gas industry (the dollar value resulting from such adjustments is referred to herein as the Adjusted Purchase Price). At the closing of the transaction contemplated by the Agreement, the Adjusted Purchase Price will be paid in shares of common stock. The number of shares of common stock to be issued will be determined by dividing the Adjusted Purchase Price by the volume weighted average (rounded to two decimal places) of the daily sale prices for the shares of the common stock for the twenty (20) consecutive trading days on which such shares are actually traded and quoted on the New York Stock Exchange ending on and including the date that is ten (10) business days prior to the special meeting of shareholders on August 10, 2012 (the Closing Share Price). During the period used to determine the Closing Share Price, the per share price of the Company s common stock has been less than $80.00, and so 4,250,000 shares will be issuable in connection with the Unadjusted Purchase Price (representing the maximum number of shares to be issued in connection with the Unadjusted Purchase Price under the terms of the Agreement). Once the adjustments to the Unadjusted Purchase Price are made, the actual amount of the Adjusted Purchase Price could result in the issuance of a number of shares in excess of or less than 4,250,000 at closing and the amount of the Adjusted Purchase Price could be more or less than $340 million. After closing of the transaction contemplated by the Agreement, any further adjustments required by the Agreement will be paid in cash, other than adjustments made to reflect the post-closing addition of properties excluded from the assets at closing due to the inability to obtain consents or the existence of preferential rights in favor of a third party, which will be paid in common stock based on the Closing Share Price.

For a description of certain lawsuits that have been brought in connection with the Agreement see *Part II, Item 1. Legal Proceedings* hereafter.

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 will be substantially complete by the end of the third quarter of 2012. The Company currently estimates it may incur a total of approximately $12 million to $15 million of cumulative costs in connection with its relocation. The Company is recognizing the majority of relocation costs in its consolidated financial statements when incurred. During the three and six months ended

June 30, 2012, the Company recognized $3.3 million and $5.1 million, respectively, of costs associated with its relocation efforts. Relocation costs amounted to $0.4 million for the six months ended June 30, 2011, all of which was recognized in the second quarter of that year. These costs are included in the caption General and administrative expenses in the unaudited condensed consolidated statements of income. Cumulative relocation costs recognized through June 30, 2012 have totaled approximately $8.3 million.

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 approximately 75% of our crude oil and natural gas production for the six months ended June 30, 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 second quarter of 2012, our crude oil and natural gas production averaged 94,852 Boe per day, an 11% increase over average daily production of 85,526 Boe per day for the first quarter of 2012 and a 76% increase over average daily production of 53,984 Boe per day for the second quarter of 2011. Crude oil and natural gas production averaged 90,189 Boe per day for the six months ended June 30, 2012, a 71% increase over average daily production of 52,830 Boe per day for the comparable 2011 period. Crude oil accounted for approximately 69% of our production for both the three and six month periods ended June 30, 2012. 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 averaged 44,530 Boe per day for the first half of 2012, a 112% increase over the first half of 2011. Second quarter 2012 average daily production in the North Dakota Bakken field increased 118% over the second quarter of 2011. Our production in the Anadarko Woodford play averaged 14,749 Boe per day for the first half of 2012, 339% higher than the same period in 2011. Anadarko Woodford average daily production increased 314% in the second quarter of 2012 compared to the second quarter of 2011.

Our crude oil and natural gas revenues for the second quarter of 2012 increased 35% to $523.4 million due to a 74% increase in sales volumes partially offset by a 23% decrease in realized commodity prices when compared to the second quarter of 2011. For the six months ended June 30, 2012, crude oil and natural gas revenues were $1,075.7 million, a 50% increase from the comparable 2011 period due to a 72% increase in sales volumes partially offset by a 12% decrease in realized commodity prices.

Our cash flows from operating activities for the first half of 2012 were $770.8 million, an increase from $429.0 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 driven mainly by increased sales volumes, partially offset by lower realized sales prices, 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 half of 2012, we invested $1,927.7 million in our capital program (including $9.6 million of seismic costs and $43.9 million of capital costs associated with increased accruals for capital expenditures), focusing primarily on increased development in the Bakken field of North Dakota and Montana and liquids-rich portions of the Anadarko Woodford play in Oklahoma. Our 2012 year-to-date capital expenditures include $362.3 million of unbudgeted property acquisitions, most notably from an 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 if and when we have the ability to increase our position in strategic plays at favorable terms.

In February 2012, we assigned certain non-strategic leaseholds and producing properties in 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. Additionally, in June 2012 we assigned certain non-strategic leaseholds and producing properties in Oklahoma to a third party for cash proceeds of $15.9 million and recognized a pre-tax gain on the transaction of $15.9 million. The disposed properties represented an immaterial portion of our total proved reserves and production. We may continue to seek opportunities to sell non-strategic crude oil and natural gas properties if and when we have the ability to dispose of such assets at favorable terms.

Significant progress was made during the 2012 second quarter with respect to the previously announced relocation of our corporate headquarters from Enid, Oklahoma to Oklahoma City, Oklahoma. During the three and six months ended June 30, 2012, we recognized $3.3 million and $5.1 million, respectively, of costs associated with our relocation efforts.

On July 26, 2012, certain terms of our credit agreement were amended. Amendments included the following, among other changes:

- Borrowing base increased from $2.25 billion to $2.75 billion;
- Aggregate credit facility commitments increased from $1.25 billion to $1.5 billion;
- Interest margins on advances were decreased by 25 basis points for all utilization levels. LIBOR margins now range from 150 to 250 basis points and reference rate margins now range from 50 to 150 basis points, depending on the percentage of the borrowing base utilized;
- Commitment fees on unused borrowing capacity were decreased from 0.50% to 0.375% when utilization of the credit facility is below 50%;
- Reduced the security requirement from 85% to 80% by value of all proved reserves and associated crude oil and natural gas properties, unless the Collateral Coverage Ratio, as defined in the amended credit agreement, is greater than or equal to 1.75 to 1.0, in which case the 80% security requirement will not apply; and
- Total Funded Debt to EBITDAX covenant ratio requirement was increased from 3.75:1.0 to 4.0:1.0.

The amendments noted above will provide us with 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).

Table of Contents

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

	Three months ended June 30, 2012	Three months ended June 30, 2011	Six months ended June 30, 2012	Six months ended June 30, 2011
Average daily production:				
Crude oil (Bbl per day)	65,274	40,382	62,587	39,420
Natural gas (Mcf per day)	177,471	81,609	165,611	80,459
Crude oil equivalents (Boe per day)	94,852	53,984	90,189	52,830
Average sales prices: [1]				
Crude oil ($/Bbl)	$ 80.56	$ 95.88	$ 85.40	$ 90.78
Natural gas ($/Mcf)	3.51	5.47	3.96	5.29
Crude oil equivalents ($/Boe)	61.69	79.86	66.31	75.63
Production expenses ($/Boe) [1]	5.16	6.65	5.17	6.52
General and administrative expenses ($/Boe) [1]	3.51	3.53	3.38	3.55
Net income (in thousands)	405,684	239,194	474,778	101,993
Diluted net income per share	2.25	1.33	2.63	0.58
EBITDAX (in thousands) [2]	421,860	285,631	876,392	554,286

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

(2) EBITDAX represents earnings before interest expense, income taxes, depreciation, depletion, amortization and accretion, property impairments, exploration expenses, non-cash gains and losses resulting from the requirements of accounting for derivatives, and non-cash equity compensation expense. EBITDAX is not a measure of net income or operating cash flows as determined by U.S. GAAP. Reconciliations of net income and operating cash flows to EBITDAX are provided subsequently under the heading *Non-GAAP Financial Measures*.

Three months ended June 30, 2012 compared to the three months ended June 30, 2011

Results of Operations

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

	Three months ended June 30, 2012	Three months ended June 30, 2011
	In thousands, except sales price data	
Crude oil and natural gas sales	$ 523,393	$ 388,784
Gain on derivative instruments, net [1]	471,728	204,453
Crude oil and natural gas service operations	9,598	9,655
Total revenues	1,004,719	602,892
Operating costs and expenses [2]	318,245	198,584
Other expenses, net	30,902	17,763
Income before income taxes	655,572	386,545
Provision for income taxes	249,888	147,351
Net income	$ 405,684	$ 239,194
Production volumes:		
Crude oil (MBbl) [3]	5,940	3,675
Natural gas (MMcf)	16,150	7,426
Crude oil equivalents (MBoe)	8,632	4,912
Sales volumes:		

Crude oil (MBbl) [(3)]	5,793	3,631
Natural gas (MMcf)	16,150	7,426

Table of Contents

Crude oil equivalents (MBoe)	8,485	4,869
Average sales prices: (4)		
Crude oil ($/Bbl)	$ 80.56	$ 95.88
Natural gas ($/Mcf)	3.51	5.47
Crude oil equivalents ($/Boe)	61.69	79.86

(1) Amounts include unrealized non-cash mark-to-market gains on derivative instruments of $478.8 million and $231.3 million for the three months ended June 30, 2012 and 2011, respectively.
(2) Net of gain on sale of assets of $17.4 million and $0.3 million for the three months ended June 30, 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 147 MBbls less than crude oil production for the three months ended June 30, 2012 and 44 MBbls less than crude oil production for the three months ended June 30, 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.

	Three months ended June 30, 2012		2011			
	Volume	Percent	Volume	Percent	Volume increase	Volume percent increase
Crude oil (MBbl)	5,940	69%	3,675	75%	2,265	62%
Natural gas (MMcf)	16,150	31%	7,426	25%	8,724	117%
Total (MBoe)	8,632	100%	4,912	100%	3,720	76%

	Three months ended June 30, 2012		2011			
	MBoe	Percent	MBoe	Percent	Volume increase	Volume percent increase
North Region	6,406	74%	3,870	79%	2,536	66%
South Region	2,129	25%	945	19%	1,184	125%
East Region	97	1%	97	2%		0%
Total	8,632	100%	4,912	100%	3,720	76%

Crude oil production volumes increased 62% during the three months ended June 30, 2012 compared to the three months ended June 30, 2011. Production increases in the Bakken field and the Anadarko Woodford play contributed incremental production volumes in 2012 of 2,170 MBbls, a 98% increase over production in these areas for the second 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 93 MBbls, or 8%, over the prior year second quarter due to new wells being completed and enhanced recovery techniques being successfully applied.

Natural gas production volumes increased 8,724 MMcf, or 117%, during the three months ended June 30, 2012 compared to the same period in 2011. Natural gas production in the Bakken field increased 2,291 MMcf, or 128%, for the three months ended June 30, 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. Natural gas

Table of Contents

production in the Anadarko Woodford play increased 5,945 MMcf, or 304%, due to additional wells being completed in the three months ended June 30, 2012 compared to the same period in 2011. Further, natural gas production increased 203 MMcf in non-Bakken areas of our North region due to the completion of new wells during the period. Natural gas production from our Arkoma Woodford properties increased 313 MMcf, or 18%, over the prior year second quarter due to the completion of new wells.

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.

Crude Oil and Natural Gas Sales. Crude oil and natural gas sales for the three months ended June 30, 2012 were $523.4 million, a 35% increase from sales of $388.8 million for the same period in 2011. Our sales volumes increased 3,616 MBoe, or 74%, 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 decreased $18.17 to $61.69 for the three months ended June 30, 2012 from $79.86 for the three months ended June 30, 2011 due to lower commodity prices and higher crude oil differentials.

The differential between NYMEX calendar month average crude oil prices and our realized crude oil price per barrel for the three months ended June 30, 2012 was $12.63 compared to $6.59 for the three months ended June 30, 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 second quarter of 2012 resulting from increased industry production in the Bakken play and higher Canadian crude oil imports, all coming off a mild 2012 winter season which decreased demand. Additionally, pipeline transportation capacity constraints in the Williston Basin have been slow to improve. These factors had a negative effect on our realized crude oil prices during the second quarter of 2012, primarily in the month of April, and resulted in higher differentials compared to 2011. Our crude oil differentials to NYMEX improved in the latter part of the 2012 second quarter, with June s differential averaging $9.37 per barrel.

Derivatives. 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. 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 in the unaudited condensed consolidated statements of income under the caption Gain (loss) on derivative instruments, net , which is a component of total revenues.

Changes in commodity futures price strips during the second quarter of 2012 had a positive impact on the fair value of our derivatives, which resulted in positive revenue adjustments of $471.7 million for the three months ended June 30, 2012. 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. The following table presents the impact on total revenues related to realized and unrealized gains and losses on derivative instruments for the periods presented.

	Three months ended June 30,	
	2012	**2011**
	In thousands	
Realized gain (loss) on derivatives:		
Crude oil derivatives	$ (10,415)	$ (34,275)
Natural gas derivatives	3,359	7,397
Total realized gain (loss) on derivatives	$ (7,056)	$ (26,878)
Unrealized gain (loss) on derivatives:		
Crude oil derivatives	$ 487,598	$ 234,751
Natural gas derivatives	(8,814)	$ (3,420)
Total unrealized gain (loss) on derivatives	$ 478,784	$ 231,331
Gain (loss) on derivative instruments, net	$ 471,728	$ 204,453

22

Table of Contents

The unrealized mark-to-market gains reflected above at June 30, 2012 relate to derivative instruments with various terms that are scheduled to be realized over the period from July 2012 to December 2014. Over this period, actual realized derivative settlements may differ significantly from the unrealized mark-to-market valuation at June 30, 2012.

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 June 30, 2012**	**2011**	**Decrease**
Average sales price ($/Bbl)	$ 90.93	$ 99.36	$ (8.43)
Sales volumes (MBbl)	64	74	(10)

The decreases in sales volumes and realized pricing reflected above resulted in a $1.5 million decrease in reclaimed oil revenue to $5.8 million for the second quarter of 2012. Offsetting this decrease was a $1.5 million increase in revenues from saltwater disposal and other services resulting from increased activity. Associated crude oil and natural gas service operations expenses decreased $0.8 million to $7.3 million for the three months ended June 30, 2012 due mainly to a decrease in the costs of purchasing and treating reclaimed crude oil for resale.

Operating Costs and Expenses

Production Expenses and Production Taxes and Other Expenses. Production expenses increased 35% to $43.8 million during the three months ended June 30, 2012 from $32.4 million during the three months ended June 30, 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 $5.16 for the three months ended June 30, 2012 compared to $6.65 per Boe for the three months ended June 30, 2011. In the prior year we experienced higher costs resulting from the abnormal rainfall and flooding in North Dakota during the 2011 second quarter. The increased costs, coupled with reduced production from curtailed and shut-in wells in North Dakota during that time, resulted in higher per-unit production expenses for the three months ending June 30, 2011.

Production taxes and other expenses increased $15.7 million, or 47%, to $49.2 million during the three months ended June 30, 2012 compared to the three months ended June 30, 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 $6.6 million and $2.7 million for the three months ended June 30, 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 revenues were 8.1% for the three months ended June 30, 2012 compared to 7.9% for the three months ended June 30, 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:

$/Boe	**Three months ended June 30, 2012**	**2011**
Production expenses	$ 5.16	$ 6.65
Production taxes and other expenses	5.80	6.88
Production expenses, production taxes and other expenses	$ 10.96	$ 13.53

Table of Contents

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.

	Three months ended June 30,	
(in thousands)	**2012**	**2011**
Geological and geophysical costs	$ 8,692	$ 3,168
Dry hole costs	10	1,866
Exploration expenses	$ 8,702	$ 5,034

Geological and geophysical costs increased $5.5 million for the three months ended June 30, 2012 due to an increase in acquisitions of seismic data in connection with our increased capital budget for 2012. No significant dry holes were drilled during the three months ended June 30, 2012.

Depreciation, Depletion, Amortization and Accretion (DD&A). Total DD&A increased $77.5 million, or 93%, in the second quarter of 2012 compared to the second quarter of 2011 primarily due to a 76% increase in production volumes. The following table shows the components of our DD&A on a unit of sales basis.

	Three months ended June 30,	
$/Boe	**2012**	**2011**
Crude oil and natural gas	$ 18.67	$ 16.66
Other equipment	0.22	0.33
Asset retirement obligation accretion	0.09	0.16
Depreciation, depletion, amortization and accretion	$ 18.98	$ 17.15

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 June 30, 2012 by $16.7 million to $35.9 million compared to $19.2 million for the three months ended June 30, 2011.

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 $12.3 million during the three months ended June 30, 2012 to $31.5 million compared to $19.2 million for the three months ended June 30, 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. Impairment provisions for proved properties were $4.3 million for the three months ended June 30, 2012, primarily reflecting uneconomic operating results in a non-Woodford single-well field in our South region. No impairment provisions for proved properties were recognized for the three months ended June 30, 2011. For the 2011 period, 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 $12.6 million to $29.8 million for the three months ended June 30, 2012 from $17.2 million for the comparable period in 2011. G&A expenses include non-cash charges for equity compensation of $7.8 million and $3.9 million for the three months ended June 30, 2012 and 2011, respectively. The increase in equity compensation in 2012 resulted from larger grants of restricted stock due to employee growth and new executive management personnel along with an increase in our grant-date stock prices, which resulted in increased expense recognition in the second quarter of 2012 compared to the second quarter of 2011. G&A expenses excluding equity compensation increased $8.7 million for the three months ended June 30, 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 545 total employees in June 2011 to 741 total employees in June 2012, a 36% increase. Additionally, in March 2011 we announced plans to relocate our corporate headquarters from Enid, Oklahoma to Oklahoma City, Oklahoma. Significant progress has been made toward our relocation efforts and we expect the relocation will be substantially complete by the end of the 2012 third quarter. For the three months ended June 30, 2012, we recognized approximately $3.3 million of costs in general and administrative expenses associated with the relocation. Cumulative relocation costs recognized through June 30, 2012 have totaled approximately $8.3 million. We currently expect to incur a total of approximately $12 million to $15 million of cumulative costs in connection with the relocation, with the majority of the balance of such costs to be incurred in the third and fourth quarters of 2012.

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

$/Boe	Three months ended June 30, 2012	2011
General and administrative expenses	$ 2.20	$ 2.66
Non-cash equity compensation	0.92	0.79
Corporate relocation expenses	0.39	0.08
General and administrative expenses	$ 3.51	$ 3.53

Interest Expense. Interest expense increased $12.9 million, or 69%, for the three months ended June 30, 2012 compared to the three months ended June 30, 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 June 30, 2012 was $2.12 billion with a weighted average interest rate of 5.5% compared to a weighted average outstanding long-term debt balance of $900.0 million and a weighted average interest rate of 7.6% 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 half of 2012 compared to the first half 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.

For the second quarter of 2012 our weighted average outstanding credit facility balance was $397.2 million with a weighted average interest rate of 2.2%. At June 30, 2012, we had $537.0 million of outstanding borrowings on our credit facility at a weighted average interest rate of 2.0%. We had no outstanding borrowings on our credit facility at June 30, 2011 and for the three months then ended.

Income Taxes. We recorded income tax expense for the three months ended June 30, 2012 of $249.9 million compared to $147.4 million for the three months ended June 30, 2011. We provide for income taxes at a combined federal and state tax rate of approximately 38% after taking into account permanent taxable differences.

Six months ended June 30, 2012 compared to the six months ended June 30, 2011

Results of operations

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

Table of Contents

	Six months ended June 30, 2012	Six months ended June 30, 2011
	In thousands, except sales price data	
Crude oil and natural gas sales	$ 1,075,651	$ 715,251
Gain (loss) on derivative instruments, net [1]	302,671	(164,850)
Crude oil and natural gas service operations	21,497	16,281
Total revenues	1,399,819	566,682
Operating costs and expenses [2]	577,754	365,267
Other expenses, net	54,399	36,225
Income before income taxes	767,666	165,190
Provision for income taxes	292,888	63,197
Net income	$ 474,778	$ 101,993
Production volumes:		
Crude oil (MBbl) [3]	11,391	7,135
Natural gas (MMcf)	30,141	14,563
Crude oil equivalents (MBoe)	16,414	9,562
Sales volumes:		
Crude oil (MBbl) [3]	11,197	7,031
Natural gas (MMcf)	30,141	14,563
Crude oil equivalents (MBoe)	16,221	9,458
Average sales prices: [4]		
Crude oil ($/Bbl)	$ 85.40	$ 90.78
Natural gas ($/Mcf)	3.96	5.29
Crude oil equivalents ($/Boe)	66.31	75.63

(1) Amounts include an unrealized non-cash mark-to-market gain on derivative instruments of $349.7 million for the six months ended June 30, 2012 and an unrealized non-cash mark-to-market loss on derivative instruments of $132.8 million for the six months ended June 30, 2011.

(2) Net of gain on sale of assets of $67.0 million and $15.6 million for the six months ended June 30, 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 194 MBbls less than crude oil production for the six months ended June 30, 2012 and 104 MBbls less than crude oil production for the six months ended June 30, 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.

Table of Contents

	Six months ended June 30, 2012 Volume	2012 Percent	2011 Volume	2011 Percent	Volume increase	Volume percent increase
Crude oil (MBbl)	11,391	69%	7,135	75%	4,256	60%
Natural gas (MMcf)	30,141	31%	14,563	25%	15,578	107%
Total (MBoe)	16,414	100%	9,562	100%	6,852	72%

	Six months ended June 30, 2012 MBoe	2012 Percent	2011 MBoe	2011 Percent	Volume increase	Volume percent increase
North Region	12,311	75%	7,530	79%	4,781	63%
South Region	3,898	24%	1,831	19%	2,067	113%
East Region	205	1%	201	2%	4	2%
Total	16,414	100%	9,562	100%	6,852	72%

Crude oil production volumes increased 60% during the six months ended June 30, 2012 compared to the six months ended June 30, 2011. Production increases in the Bakken field and the Anadarko Woodford play contributed incremental production volumes in 2012 of 4,016 MBbls, a 94% increase over production in these areas for the same period in 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 217 MBbls, or 9%, in 2012 due to new wells being completed and enhanced recovery techniques being successfully applied.

Natural gas production volumes increased 15,578 MMcf, or 107%, during the six months ended June 30, 2012 compared to the same period in 2011. Natural gas production in the Bakken field increased 4,377 MMcf, or 127%, for the six months ended June 30, 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. Natural gas production in the Anadarko Woodford play increased 10,776 MMcf, or 331%, due to additional wells being completed in the six months ended June 30, 2012 compared to the same period in 2011. Further, natural gas production increased 372 MMcf in non-Bakken areas of our North region due to the completion of new wells during the period.

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.

Crude Oil and Natural Gas Sales. Crude oil and natural gas sales for the six months ended June 30, 2012 were $1,075.7 million, a 50% increase from sales of $715.3 million for the same period in 2011. Our sales volumes increased 6,763 MBoe, or 72%, 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 decreased $9.32 to $66.31 for the six months ended June 30, 2012 from $75.63 for the six months ended June 30, 2011 due to lower commodity prices and higher crude oil differentials.

The differential between NYMEX calendar month average crude oil prices and our realized crude oil price per barrel for the six months ended June 30, 2012 was $12.45 compared to $7.86 for the six months ended June 30, 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 2012 resulting from increased industry production in the Bakken play and higher Canadian crude oil imports, all coming off a mild 2012 winter season which decreased demand. Additionally, pipeline transportation capacity constraints in the Williston Basin have been slow to improve. These factors had a negative effect on our realized crude oil prices during 2012, primarily in the months of March and April, and resulted in higher differentials compared to 2011. Our crude oil differentials to NYMEX improved in the latter part of the second quarter of 2012, with June s differential averaging $9.37 per barrel.

Derivatives. Changes in commodity futures price strips during the six months ended June 30, 2012 had an overall positive impact on the fair value of our derivative instruments, which resulted in positive revenue adjustments of $302.7 million for the year-to-date period. 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. The following table presents the impact on total revenues related to realized and unrealized gains and losses on derivative instruments for the periods presented.

27

Table of Contents

	Six months ended June 30, 2012	2011
	In thousands	
Realized gain (loss) on derivatives:		
Crude oil derivatives	$ (52,759)	$ (47,617)
Natural gas derivatives	5,778	15,523
Total realized gain (loss) on derivatives	$ (46,981)	$ (32,094)
Unrealized gain (loss) on derivatives:		
Crude oil derivatives	$ 347,657	$ (125,380)
Natural gas derivatives	1,995	(7,376)
Total unrealized gain (loss) on derivatives	$ 349,652	$ (132,756)
Gain (loss) on derivative instruments, net	$ 302,671	$ (164,850)

The unrealized mark-to-market gains reflected above at June 30, 2012 relate to derivative instruments with various terms that are scheduled to be realized over the period from July 2012 to December 2014. Over this period, actual realized derivative settlements may differ significantly from the unrealized mark-to-market valuation at June 30, 2012.

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	Six months ended June 30, 2012	2011	Increase
Average sales price ($/Bbl)	$ 96.28	$ 95.25	$ 1.03
Sales volumes (MBbl)	149	126	23

The increases in sales volumes and realized pricing reflected above resulted in a $2.3 million increase in reclaimed oil revenue to $14.4 million for the six months ended June 30, 2012. Additionally, revenues from saltwater disposal and other services increased $2.9 million resulting from increased activity. Associated crude oil and natural gas service operations expenses increased $3.6 million to $17.1 million during the six months ended June 30, 2012 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 36% to $83.8 million during the six months ended June 30, 2012 from $61.6 million during the six months ended June 30, 2011. This increase is primarily the result of higher production volumes from an increase in the number of producing wells. Production expense per Boe decreased to $5.17 for the six months ended June 30, 2012 from $6.52 per Boe for the six months ended June 30, 2011. In the prior year we experienced higher costs resulting from the abnormal rainfall and flooding in North Dakota during the 2011 second quarter. The increased costs, coupled with reduced production from curtailed and shut-in wells in North Dakota during that time, resulted in higher per-unit production expenses for the six months ending June 30, 2011.

Production taxes and other expenses increased $38.9 million, or 64%, to $100.0 million during the six months ended June 30, 2012 compared to the six months ended June 30, 2011 primarily as a result of higher crude oil and natural gas revenues resulting from increased sales volumes. Production taxes and other expenses on the unaudited condensed consolidated statements of income include other charges for marketing, gathering, dehydration and compression fees primarily related to natural gas sales in the Oklahoma Woodford and North Dakota Bakken areas of $12.0 million and $4.9 million for the six months ended June 30, 2012 and 2011, respectively. The increase in other charges is primarily due to the significant increase in natural gas sales volumes in the current year. Production taxes, excluding other charges, as a percentage of crude oil and natural gas revenues were 8.1% for the six months ended June 30, 2012 compared to 7.8% for the six months ended June 30, 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. 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:

	Six months ended June 30,	
$/Boe	**2012**	**2011**
Production expenses	$ 5.17	$ 6.52
Production taxes and other expenses	6.16	6.46
Production expenses, production taxes and other expenses	$ 11.33	$ 12.98

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.

	Six months ended June 30,	
(in thousands)	**2012**	**2011**
Geological and geophysical costs	$ 12,755	$ 8,476
Dry hole costs	98	3,370
Exploration expenses	$ 12,853	$ 11,846

Geological and geophysical costs increased $4.3 million for the six months ended June 30, 2012 due to an increase in acquisitions of seismic data in connection with our increased capital budget for 2012. No significant dry holes were drilled during the six months ended June 30, 2012.

Depreciation, Depletion, Amortization and Accretion. Total DD&A increased $151.3 million, or 95%, in the first half of 2012 compared to the first half of 2011 primarily due to a 72% increase in production volumes. The following table shows the components of our DD&A on a unit of sales basis.

	Six months ended June 30,	
$/Boe	**2012**	**2011**
Crude oil and natural gas	$ 18.79	$ 16.37
Other equipment	0.26	0.29
Asset retirement obligation accretion	0.09	0.17
Depreciation, depletion, amortization and accretion	$ 19.14	$ 16.83

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

Property Impairments. Property impairments increased in the six months ended June 30, 2012 by $25.7 million to $65.8 million compared to $40.1 million for the six months ended June 30, 2011.

Impairments of non-producing properties increased $21.4 million during the six months ended June 30, 2012 to $61.5 million compared to $40.1 million for the six months ended June 30, 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.

Impairment provisions for proved properties were $4.3 million for the six months ended June 30, 2012, primarily reflecting uneconomic operating results in a non-Woodford single-well field in our South region. No impairment provisions for proved properties were recognized for the six months ended June 30, 2011. For the 2011 period, future cash flows were determined to be in excess of cost basis, therefore no impairment was necessary.

General and Administrative Expenses. G&A expenses increased $21.2 million to $54.8 million during the six months ended June 30, 2012 from $33.6 million during the comparable period in 2011. G&A expenses include non-cash charges for equity compensation of $13.3 million and $7.5 million for the six months ended June 30, 2012 and 2011, respectively. The increase in equity compensation in 2012 resulted from larger grants of restricted stock due to employee growth and new executive management personnel along with an increase in our grant-date stock prices, which resulted in increased expense recognition in 2012 compared to the prior year. G&A expenses excluding equity compensation increased $15.4 million for the six months ended June 30, 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 545 total employees in June 2011 to 741 total employees in June 2012, a 36% increase. Additionally, in March 2011 we announced plans to relocate our corporate headquarters from Enid, Oklahoma to Oklahoma City, Oklahoma. Significant progress has been made toward our relocation efforts and we expect the relocation will be substantially complete by the end of the 2012 third quarter. For the six months ended June 30, 2012, we recognized approximately $5.1 million of costs in general and administrative expenses associated with the relocation. Cumulative relocation costs recognized through June 30, 2012 have totaled approximately $8.3 million. We currently expect to incur a total of approximately $12 million to $15 million of cumulative costs in connection with the relocation, with the majority of the balance of such costs to be incurred in the third and fourth quarters of 2012.

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

	Six months ended June 30,	
$/Boe	**2012**	**2011**
General and administrative expenses	$ 2.25	$ 2.72
Non-cash equity compensation	0.82	0.79
Corporate relocation expenses	0.31	0.04
General and administrative expenses	$ 3.38	$ 3.55

Interest Expense. Interest expense increased $18.2 million, or 48%, for the six months ended June 30, 2012 compared to the same period in 2011 due to an increase in our weighted average outstanding long-term debt obligations. Our weighted average outstanding long-term debt balance for the six months ended June 30, 2012 was $1.86 billion with a weighted average interest rate of 5.6% compared to a weighted average outstanding long-term debt balance of $939.3 million and a weighted average interest rate of 7.4% 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 half of 2012 compared to the first half 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.

For the six months ended June 30, 2012 our weighted average outstanding credit facility balance increased to $434.3 million compared to $39.3 million for the six months ended June 30, 2011. The weighted average interest rate on our credit facility borrowings was 2.3% for the six months ended June 30, 2012 compared to 2.6% for the same period in 2011. At June 30, 2012, we had $537.0 million of outstanding borrowings on our credit facility at a weighted average interest rate of 2.0%.

Income Taxes. We recorded income tax expense for the six months ended June 30, 2012 of $292.9 million compared to $63.2 million for the six months ended June 30, 2011. We provide for income taxes at a combined federal and state tax rate of approximately 38% after taking into account permanent taxable differences.

30

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 72% increase in sales volumes for the first six 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 as we have more borrowing availability on our credit facility resulting from the July 2012 increase in our credit facility s borrowing base from $2.25 billion to $2.75 billion and associated increase in aggregate commitments from $1.25 billion to $1.5 billion as discussed below under the heading *Revolving Credit Facility*.

As of August 1, 2012, we had $823.6 million of borrowing availability on our credit facility after considering the increased commitments and outstanding borrowings and letters of credit.

Cash Flows

Cash Flows from Operating Activities

Our net cash provided by operating activities was $770.8 million and $429.0 million for the six months ended June 30, 2012 and 2011, respectively. The increase in operating cash flows was primarily due to higher crude oil and natural gas revenues driven by higher sales volumes, partially offset by lower realized sales prices, 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 six months ended June 30, 2012 and 2011, we had cash flows used in investing activities (excluding asset sales) of $1,874.3 million and $826.4 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 larger capital budget and drilling program for 2012 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 $100.8 million for the first half 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 $22.8 million for the first half 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 six months ended June 30, 2012 was $978.3 million primarily resulting from the receipt of $787.0 million of net proceeds, after deducting the initial purchasers fees, from the issuance of $800 million of 5% Senior Notes due 2022 (the 2022 Notes) in March 2012, net borrowings of $179.0 million on our credit facility, and proceeds received from the $22 million 10-year amortizing term loan executed in February 2012. Net cash provided by financing activities of $628.1 million for the six months ended June 30, 2011 was mainly the result of receiving $659.7 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 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.

Table of Contents

Revolving Credit Facility

On July 26, 2012, certain terms of our credit agreement were amended. Amendments included the following, among other changes:

- Borrowing base increased from $2.25 billion to $2.75 billion;
- Aggregate credit facility commitments increased from $1.25 billion to $1.5 billion;
- Interest margins on advances were decreased by 25 basis points for all utilization levels. LIBOR margins now range from 150 to 250 basis points and reference rate margins now range from 50 to 150 basis points, depending on the percentage of the borrowing base utilized;
- Commitment fees on unused borrowing capacity were decreased from 0.50% to 0.375% when utilization of the credit facility is below 50%;
- Reduced the security requirement from 85% to 80% by value of all proved reserves and associated crude oil and natural gas properties, unless the Collateral Coverage Ratio, as defined in the amended credit agreement, is greater than or equal to 1.75 to 1.0, in which case the 80% security requirement will not apply; and
- Total Funded Debt to EBITDAX covenant ratio requirement was increased from 3.75:1.0 to 4.0:1.0.

The amended credit facility terms will provide us with 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 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.

The commitments under our credit facility, which matures on July 1, 2015, are from a syndicate of 14 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 $1.5 billion commitment.

We had $537.0 million of outstanding borrowings on our credit facility at June 30, 2012 and $358.0 million outstanding at December 31, 2011. As of June 30, 2012, we had approximately $708.6 million of borrowing availability under our credit facility (after considering outstanding borrowings and letters of credit). As of August 1, 2012, we had $672 million of outstanding borrowings and approximately $823.6 million of borrowing availability under our credit facility after considering our increased level of commitments.

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 4.0 to 1.0, effective July 26, 2012. 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, non-cash gains and losses resulting from the requirements of accounting for derivatives, and non-cash equity compensation expense. EBITDAX is not a measure of net income or operating cash flows as determined by U.S. GAAP. Reconciliations of net income and operating cash flows to EBITDAX are 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 June 30, 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 and such event could result in an acceleration of other outstanding indebtedness. 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 fourth 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.

Table of Contents

Senior Notes

On March 8, 2012, we issued $800 million of 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 under our credit facility.

The following table summarizes the maturity dates, semi-annual interest payment dates, and optional redemption periods related to our outstanding Senior Note obligations.

	2019 Notes	2020 Notes	2021 Notes	2022 Notes
Maturity date	October 1, 2019	October 1, 2020	April 1, 2021	September 15, 2022
Semi-annual interest payment dates	April 1, October 1	April 1, October 1	April 1, October 1	March 15, Sept. 15
Decreasing call premium redemption period (1)	October 1, 2014	October 1, 2015	April 1, 2016	March 15, 2017
Make-whole redemption period (2)	October 1, 2014	October 1, 2015	April 1, 2016	March 15, 2017
Redemption using equity offering proceeds (3)	October 1, 2012	October 1, 2013	April 1, 2014	March 15, 2015

(1) On or after these dates, we have the option to redeem all or a portion of our Senior Notes at the decreasing redemption prices specified in the respective Senior Note indentures (together, the Indentures) plus any accrued and unpaid interest to the date of redemption.

(2) At any time prior to these dates, we have the option to redeem all or a portion of our Senior Notes at the make-whole redemption prices specified in the Indentures plus any accrued and unpaid interest to the date of redemption.

(3) At any time prior to these dates, we may redeem up to 35% of the principal amount of our Senior Notes under certain circumstances with the net cash proceeds from one or more equity offerings at the redemption prices specified in the Indentures plus any accrued and unpaid interest to the date of redemption.

Currently, we have no plans or intentions of exercising an early redemption option on the Senior Notes. Our Senior 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 June 30, 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 Senior Notes. Our other subsidiary, the value of whose assets and operations are minor, does not guarantee the Senior 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 June 30, 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.

Table of Contents

During the first six months of 2012, we participated in the completion of 356 gross (148.8 net) wells and invested a total of $1,927.7 million in our capital program (including $9.6 million of seismic costs and $43.9 million of capital costs associated with increased accruals for capital expenditures). Our 2012 year-to-date capital expenditures include $362.3 million of unbudgeted property acquisitions, most notably from an acquisition of producing and undeveloped properties in the Bakken play of North Dakota in February 2012 for $276 million, of which $51.7 million was allocated to producing properties. Our 2012 year-to-date capital expenditures were allocated as follows.

	Amount ***in millions***
Exploration and development drilling	$ 1,427.9
Land costs	73.7
Capital facilities, workovers and re-completions	22.1
Buildings, vehicles, computers and other equipment	32.1
Seismic	9.6
Capital expenditures, excluding acquisitions	$ 1,565.4
Acquisitions of producing properties	63.3
Acquisitions of non-producing properties	299.0
Total acquisitions	$ 362.3
Total capital expenditures	$ 1,927.7

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 June 30, 2012 are ahead of plan. During the first half of 2012, we achieved improved drilling times for new wells in the Bakken field, 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. Further, we have realized higher average working interests in operated and non-operated properties than planned, resulting in increased capital expenditures. In addition, completed well costs on operated and non-operated properties are trending higher than planned partly due to an increase in the number of completion stages being used on North Dakota Bakken wells along with inflationary pressure on the costs of oilfield services and equipment. Given these factors and the continued success of our drilling program during the 2012 second quarter, in August 2012 our Board of Directors approved an increase to our 2012 capital expenditures budget to $3.0 billion, excluding property acquisitions. Our previous 2012 capital expenditures budget was $2.3 billion. The revised budget primarily reflects an increase in planned exploratory and development drilling 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	$ 2,700
Land costs	165
Capital facilities, workovers and re-completions	70
Buildings, vehicles, computers and other equipment	45
Seismic	20
Total	$ 3,000

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 the remainder of our 2012 capital program. 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.

34

Commitments

As of June 30, 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 June 30, 2012 total approximately $184 million, of which $102 million is expected to be incurred in the remainder of 2012, $67 million in 2013, and $15 million in 2014. We expect to continue to enter into additional drilling rig contracts to help mitigate the risk of experiencing equipment shortages and 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 June 30, 2012 amount to approximately $28 million, of which $11 million is expected to be incurred in the remainder of 2012 and $17 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 $2 million as of June 30, 2012. The commitments under these arrangements are not recorded in the accompanying condensed consolidated balance sheets.

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 extending through December 2015 and require us to pay varying per-barrel transportation charges on volumes ranging from 2,500 to 10,000 barrels of crude oil per day. Future commitments remaining as of June 30, 2012 under the rail transportation arrangements amount to approximately $69 million, of which $17 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 will be substantially complete by the end of the third quarter of 2012. We currently estimate we may incur a total of approximately $12 million to $15 million of cumulative costs in connection with our relocation. Cumulative relocation costs recognized through June 30, 2012 have totaled approximately $8.3 million, of which $5.1 million was incurred during the six months ended June 30, 2012. The majority of the remaining expected relocation costs will be incurred and recognized in the third and fourth quarters of 2012. Relocation costs are included in the caption General and administrative expenses in the unaudited condensed consolidated statements of income.

Potential Issuance of Common Stock in Conjunction with Proposed Acquisition

On March 27, 2012, the Company entered into a Reorganization and Purchase and Sale Agreement (the Agreement) with Wheatland Oil Inc. (Wheatland), and the shareholders of Wheatland. Wheatland is owned 75% by the Revocable Inter Vivos Trust of Harold G. Hamm, a trust of which Harold G. Hamm, our Chief Executive Officer, Chairman of the Board and principal shareholder is the trustee and sole beneficiary, and 25% by our Vice Chairman of Strategic Growth Initiatives, Jeffrey B. Hume. The Company s Board of Directors formed a special committee comprised of independent board members to protect the interests of the Company and its minority shareholders in connection with the Agreement. The special committee negotiated the Agreement with Wheatland and its shareholders.

The Agreement provides for the acquisition by the Company of all of Wheatland s right, title and interest in and to certain crude oil and natural gas properties and related assets, in which the Company also owns an interest, in the states of Mississippi, Montana, North Dakota and Oklahoma and the assumption of certain liabilities related thereto. Wheatland s assets included in the transaction are primarily comprised of approximately 37,900 net acres in the North Dakota and Montana Bakken play and interests in producing properties with production of approximately 2,500 net barrels of oil equivalent per day as of December 31, 2011.

Table of Contents

The Company is holding a shareholder vote on the proposed transaction as required by New York Stock Exchange rules and the terms of the Agreement. The New York Stock Exchange Listed Company Manual requires the approval by a majority of votes cast at the special meeting, provided the total vote cast represents over 50% in interest of all securities entitled to vote on the matter. Oklahoma state law requires any proposal submitted to the Company s shareholders be approved by a majority of the shares present in person or represented by proxy and entitled to vote on the matter. In addition, the Agreement requires the Company to obtain approval of a majority of the issued and outstanding shares held by shareholders other than members of the Company s Board of Directors, its executive officers, Mr. Hamm and his affiliates, and Mr. Hume and his affiliates (referred to herein as the Unaffiliated Vote Requirement). If the issuance of shares pursuant to the Agreement does not receive the required approvals, the Agreement will terminate without the payment of fees by any party. A shareholder meeting will be held on August 10, 2012 for the purpose of voting whether to approve the issuance of shares pursuant to the Agreement.

The purchase price for the assets consists of $340 million (the Unadjusted Purchase Price), subject to customary purchase price adjustments associated with transactions of this nature in the oil and gas industry (the dollar value resulting from such adjustments is referred to herein as the Adjusted Purchase Price). At the closing of the transaction contemplated by the Agreement, the Adjusted Purchase Price will be paid in shares of common stock. The number of shares of common stock to be issued will be determined by dividing the Adjusted Purchase Price by the volume weighted average (rounded to two decimal places) of the daily sale prices for the shares of the common stock for the twenty (20) consecutive trading days on which such shares are actually traded and quoted on the New York Stock Exchange ending on and including the date that is ten (10) business days prior to the special meeting of shareholders on August 10, 2012 (the Closing Share Price). During the period used to determine the Closing Share Price, the per share price of the Company s common stock has been less than $80.00, and so 4,250,000 shares will be issuable in connection with the Unadjusted Purchase Price (representing the maximum number of shares to be issued in connection with the Unadjusted Purchase Price under the terms of the Agreement). Once the adjustments to the Unadjusted Purchase Price are made, the actual amount of the Adjusted Purchase Price could result in the issuance of a number of shares in excess of or less than 4,250,000 at closing and the amount of the Adjusted Purchase Price could be more or less than $340 million. After closing of the transaction contemplated by the Agreement, any further adjustments required by the Agreement will be paid in cash, other than adjustments made to reflect the post-closing addition of properties excluded from the assets at closing due to the inability to obtain consents or the existence of preferential rights in favor of a third party, which will be paid in common stock based on the Closing Share Price. The issuance of equity securities in connection with the Agreement could have a dilutive effect on the value of our common stock.

For a description of certain lawsuits that have been brought in connection with the Agreement see *Part II, Item 1. Legal Proceedings* hereafter.

Critical Accounting Policies

There have been no changes 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 Financial Accounting Standards Board (FASB) issued Accounting Standards Update (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 International Accounting Standards Board. 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, and accounting for financial instruments. 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, non-cash gains and losses resulting from the requirements of accounting for derivatives, and non-cash equity compensation expense. EBITDAX is

not a measure of net income or operating 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 and operating cash flows 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 operating 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. At June 30, 2012, our credit facility required 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, which was subsequently amended to 4.0 to 1.0 effective July 26, 2012. 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 June 30, 2012. A violation of this covenant in the future could result in a default under our credit facility and such event could result in an acceleration of other outstanding indebtedness. 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.

	Three months ended June 30,		**Six months ended June 30,**	
in thousands	**2012**	**2011**	**2012**	**2011**
Net income	$ 405,684	$ 239,194	$ 474,778	$ 101,993
Interest expense	31,691	18,785	55,969	37,756
Provision for income taxes	249,888	147,351	292,888	63,197
Depreciation, depletion, amortization and accretion	161,018	83,501	310,473	159,151
Property impairments	35,871	19,242	65,778	40,090
Exploration expenses	8,702	5,034	12,853	11,846
Impact from derivative instruments:				
Total (gain) loss on derivatives, net	(471,728)	(204,453)	(302,671)	164,850
Total realized loss (cash outflow) on derivatives, net	(7,056)	(26,878)	(46,981)	(32,094)
Non-cash (gain) loss on derivatives, net	(478,784)	(231,331)	(349,652)	132,756
Non-cash equity compensation	7,790	3,855	13,305	7,497
EBITDAX	$ 421,860	$ 285,631	$ 876,392	$ 554,286

The following table provides a reconciliation of our net cash provided by operating activities to EBITDAX for the periods presented.

	Six months ended June 30,	
	2012	**2011**
	in thousands	
Net cash provided by operating activities	$ 770,830	$ 428,966
Current income tax provision	2,150	960
Interest expense	55,969	37,756
Exploration expenses, excluding dry hole costs	12,755	8,476
Gain on sale of assets, net	67,024	15,575
Other, net	(6,169)	(3,832)
Changes in assets and liabilities	(26,167)	66,385
EBITDAX	$ 876,392	$ 554,286

37

Table of Contents

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 six months ended June 30, 2012, and excluding any effect of our derivative instruments in place, our annual revenue would increase or decrease by approximately $229 million for each $10.00 per barrel change in crude oil prices and $61 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.

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 six months ended June 30, 2012 had an overall positive impact on the fair value of our derivative instruments. For the six months ended June 30, 2012, we realized a net loss on derivatives of $47.0 million and reported an unrealized non-cash mark-to-market gain on derivatives of $349.7 million. The fair value of our derivative instruments at June 30, 2012 was a net asset of $185.4 million. The mark-to-market net asset relates to derivative instruments with various terms that are scheduled to be realized over the period from July 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 June 30, 2012. An assumed increase in the forward commodity prices used in the June 30, 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 $119 million at June 30, 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 increase our net derivative asset to approximately $484 million at June 30, 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 ($372.3 million in receivables at June 30, 2012), our joint interest receivables ($387.8 million at June 30, 2012), and counterparty credit risk associated with our derivative instrument receivables ($185.4 million at June 30, 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 $73.9 million at June 30, 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.

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. Substantially all of 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 $672 million of outstanding borrowings under our credit facility at August 1, 2012. The impact of a 1% increase in interest rates on this amount of debt would result in increased interest expense of approximately $6.7 million per year and a $4.2 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 August 1, 2012 was 1.8%.

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 June 30, 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 June 30, 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

Except as set forth below, during the six months ended June 30, 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.

On June 12, 2012, the Louisiana Municipal Police Employees Retirement System (MPERS), a purported shareholder, filed a lawsuit against the Company, Wheatland, Harold G. Hamm, Jeffrey B. Hume and the directors serving on the special committee formed in connection with the proposed transaction with Wheatland in the United States District Court for the Western District of Oklahoma. In the complaint, MPERS alleges each of the individuals named in the lawsuit breached fiduciary duties in connection with their participation in the Wheatland transaction, and the Company failed to provide its shareholders with sufficient material information to enable them to make an informed decision regarding whether to approve the transaction. In its prayer for relief, MPERS seeks the following relief: (i) enjoin the consummation of the Wheatland transaction (or rescission of the transaction if consummated); (ii) enjoin the trusts benefitting the children of Mr. Hamm from voting in connection with the Unaffiliated Vote Requirement; and (iii) recover costs and attorney fees in connection with the lawsuit.

On July 18, 2012, a second lawsuit was filed by Winston O. Watkins, a purported shareholder, as a derivative action against the Company as a nominal defendant, Wheatland, Mr. Hamm, Mr. Hume and the directors serving on the special committee formed in connection with the proposed transaction with Wheatland in the District Court of Oklahoma County, State of Oklahoma. The Complaint contains allegations against the defendants similar to those described in the lawsuit brought by MPERS, but in his prayer for relief, Mr. Watkins seeks the following relief: (i) a declaration that the lawsuit is properly maintainable as a class action and/or derivative action; (ii) an award of damages; (iii) equitable relief; and (iv) recover costs and attorney fees in connection with the lawsuit.

See *Note 10. Proposed Property Transaction with Related Party* in *Notes to Unaudited Condensed Consolidated Financial Statements* of this Form 10-Q for further discussion of the Wheatland transaction.

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 June 30, 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)
April 1, 2012 to April 30, 2012	3,682	$ 87.60		
May 1, 2012 to May 31, 2012	3,318	$ 73.51		
June 1, 2012 to June 30, 2012	11,587	$ 67.28		
Total	18,587	$ 72.42		

(1) In connection with restricted stock grants under the Continental Resources, Inc. 2005 Long-Term Incentive Plan (2005 Plan), we adopted a policy that enables employees to surrender shares to cover their tax liability. All shares purchased above represent shares surrendered to cover tax liabilities. We paid the associated taxes to the Internal Revenue Service.

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

(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.

ITEM 3. Defaults Upon Senior Securities

Not applicable.

Table of Contents

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.

Table of Contents

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: August 8, 2012

By: /s/ John D. Hart
John D. Hart
Sr. Vice President, Chief Financial Officer and Treasurer

(Duly Authorized Officer and Principal Financial Officer)

Table of Contents

Index to Exhibits

3.1	Third Amended and Restated Certificate of Incorporation of Continental Resources, Inc. filed February 24, 2012 as Exhibit 3.1 to the Company s 2011 Form 10-K (Commission File No. 001-32886) and incorporated herein by reference.
3.2	Second Amended and Restated Bylaws of Continental Resources, Inc. filed February 24, 2012 as Exhibit 3.2 to the Company s 2011 Form 10-K (Commission File No. 001-32886) 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