CONTINENTAL RESOURCES, INC
Form 10-Q
August 08, 2013
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, 2013

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 (State or other jurisdiction of incorporation or organization)	73-0767549 (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

185,638,546 shares of our $0.01 par value common stock were outstanding on August 1, 2013.

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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 defined in this section may be 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.

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

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

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

"DD&A" Depreciation, depletion, amortization and accretion.

"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 horizontally 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.

"MMBoe" One million Boe.

"MMBtu" One million British thermal units.

"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.

"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 additional seismic data processing and interpretation.

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

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

"proved undeveloped reserves" or "PUD" Proved reserves expected to be recovered from new wells on undrilled acreage or from existing wells where a relatively major expenditure is required for recompletion.

"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.

"SCOOP" Refers to the South Central Oklahoma Oil Province, a term we use to describe an emerging area of crude oil and liquids-rich natural gas properties located in the Anadarko basin of south central Oklahoma.

"unconventional play" An area believed to be capable of producing crude oil and natural gas occurring in accumulations that are regionally extensive, but may lack readily apparent traps, seals and discrete hydrocarbon-water boundaries that typically define conventional reservoirs. 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, and generally require horizontal drilling, fracture stimulation treatments or other special recovery processes in order to achieve economic production.

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

Cautionary Statement for the Purpose of the "Safe Harbor" Provisions of the Private Securities Litigation Reform Act of 1995

This report includes "forward-looking statements" within the meaning of Section 27A of the Securities Act of 1933 and Section 21E of the Securities Exchange Act of 1934. All statements other than statements of historical fact, including, but not limited to, statements or information concerning the Company's future operations, performance, financial condition, production and reserves, schedules, plans, timing of development, returns, budgets, costs, business strategy, objectives, and cash flow, included in this report are forward-looking statements. When used in this report, the words "could," "may," "believe," "anticipate," "intend," "estimate," "expect," "project," "budget," "plan," "continue," "potential," "g and similar expressions are intended to identify forward-looking statements, although not all forward-looking statements contain such identifying words. Forward-looking statements are based on the Company's current expectations and assumptions about future events and currently available information as to the outcome and timing of future events. Although the Company believes the expectations reflected in the forward-looking statements are reasonable and based on reasonable assumptions, no assurance can be given that such expectations will be correct or achieved or that the assumptions are accurate. 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, 2012, 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, natural gas liquids, and natural gas prices and differentials;
- the timing and amount of future production of crude oil and natural gas and flaring activities;
- the amount, nature and timing of capital expenditures;
- estimated revenues, expenses and results of operations;
- drilling and completing of wells;
- competition;
- marketing of crude oil and natural gas;
- transportation of crude oil, natural gas liquids, 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 governmental policies, laws and regulations, as well as regulatory and legal proceedings involving us and of scheduled or potential regulatory or legal changes;
- our future operating results;
- plans, objectives, expectations and intentions contained in this report that are not historical, including, without limitation, statements regarding our future growth plans;
- our commodity hedging arrangements; and
- the ability and willingness of current or potential lenders, hedging contract counterparties, customers, and working interest owners to fulfill their obligations to us or to enter into transactions with us in the future on terms that are acceptable to us.

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, completion 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, 2012, 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.

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

In thousands, except par values and share data	June 30, 2013 (Unaudited)	December 31, 2012
Assets		
Current assets:		
Cash and cash equivalents	$220,413	$35,729
Receivables:		
Crude oil and natural gas sales	584,392	468,650
Affiliated parties	15,902	12,410
Joint interest and other, net	339,388	356,111
Derivative assets	76,478	18,389
Inventories	42,085	46,743
Deferred and prepaid taxes	6,425	365
Prepaid expenses and other	8,547	8,386
Total current assets	1,293,630	946,783
Net property and equipment, based on successful efforts method of accounting	9,440,216	8,105,269
Net debt issuance costs and other	74,570	55,726
Noncurrent derivative assets	91,566	32,231
Total assets	$10,899,982	$9,140,009
Liabilities and shareholders' equity		
Current liabilities:		
Accounts payable trade	$769,249	$687,310
Revenues and royalties payable	276,446	261,856
Payables to affiliated parties	5,476	6,069
Accrued liabilities and other	195,501	153,454
Derivative liabilities	6,809	12,999
Current portion of asset retirement obligations	1,964	2,227
Current portion of long-term debt	1,981	1,950
Total current liabilities	1,257,426	1,125,865
Long-term debt, net of current portion	4,440,820	3,537,771
Other noncurrent liabilities:		
Deferred income tax liabilities	1,510,511	1,262,576
Asset retirement obligations, net of current portion	45,568	44,944
Noncurrent derivative liabilities	—	2,173
Other noncurrent liabilities	2,317	2,981
Total other noncurrent liabilities	1,558,396	1,312,674
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; 185,642,832 shares issued and outstanding at June 30, 2013; 185,604,681 shares issued and outstanding at December 31, 2012	1,856	1,856
Additional paid-in capital	1,242,579	1,226,835

Retained earnings	2,398,905	1,935,008
Total shareholders' equity	3,643,340	3,163,699
Total liabilities and shareholders' equity	$10,899,982	$9,140,009

The accompanying notes are an integral part of these condensed consolidated financial statements.
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Continental Resources, Inc. and Subsidiaries
Unaudited Condensed Consolidated Statements of Income

	Three months ended June 30,		Six months ended June 30,	
	2013	2012	2013	2012
In thousands, except per share data				
Revenues				
Crude oil and natural gas sales	$864,538	$511,192	$1,627,170	$1,046,504
Crude oil and natural gas sales to affiliates	27,649	12,201	48,534	29,147
Gain on derivative instruments, net	199,056	471,728	114,225	302,671
Crude oil and natural gas service operations	9,509	9,598	21,052	21,497
Total revenues	1,100,752	1,004,719	1,810,981	1,399,819
Operating costs and expenses				
Production expenses	73,143	43,479	134,460	83,495
Production and other expenses to affiliates	1,495	1,427	3,152	2,496
Production taxes and other expenses	81,050	48,077	152,308	97,807
Exploration expenses	11,151	8,702	20,965	12,853
Crude oil and natural gas service operations	7,317	7,255	15,914	17,097
Depreciation, depletion, amortization and accretion	236,790	161,018	450,468	310,473
Property impairments	79,712	35,871	119,793	65,778
General and administrative expenses	35,873	29,813	69,690	54,779
(Gain) loss on sale of assets, net	349	(17,397)	213	(67,024)
Total operating costs and expenses	526,880	318,245	966,963	577,754
Income from operations	573,872	686,474	844,018	822,065
Other income (expense):				
Interest expense	(61,378)	(31,691)	(108,853)	(55,969)
Other	634	789	1,180	1,570
	(60,744)	(30,902)	(107,673)	(54,399)
Income before income taxes	513,128	655,572	736,345	767,666
Provision for income taxes	189,858	249,888	272,448	292,888
Net income	$323,270	$405,684	$463,897	$474,778
Basic net income per share	$1.76	$2.26	$2.52	$2.64
Diluted net income per share	$1.75	$2.25	$2.51	$2.63

The accompanying notes are an integral part of these condensed consolidated financial statements.
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Continental Resources, Inc. and Subsidiaries
Condensed Consolidated Statements of Shareholders' Equity

In thousands, except share data	Shares outstanding	Common stock	Additional paid-in capital	Retained earnings	Total shareholders' equity
Balance at December 31, 2012	185,604,681	$1,856	$1,226,835	$1,935,008	$3,163,699
Net income (unaudited)	—	—	—	463,897	463,897
Stock-based compensation (unaudited)	—	—	19,003	—	19,003
Restricted stock:					
Issued (unaudited)	129,850	1	—	—	1
Repurchased and canceled (unaudited)	(38,876)	—	(3,259)	—	(3,259)
Forfeited (unaudited)	(52,823)	(1)	—	—	(1)
Balance at June 30, 2013	185,642,832	$1,856	$1,242,579	$2,398,905	$3,643,340

The accompanying notes are an integral part of these condensed consolidated financial statements.
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Continental Resources, Inc. and Subsidiaries
Unaudited Condensed Consolidated Statements of Cash Flows

	Six months ended June 30,	
In thousands	2013	2012
Cash flows from operating activities		
Net income	$463,897	$474,778
Adjustments to reconcile net income to net cash provided by operating activities:		
Depreciation, depletion, amortization and accretion	448,639	314,367
Property impairments	119,793	65,778
Change in fair value of derivatives	(125,787)	(349,652)
Stock-based compensation	18,998	13,305
Provision for deferred income taxes	266,618	290,738
Dry hole costs	8,063	98
(Gain) loss on sale of assets, net	213	(67,024)
Other, net	2,466	2,275
Changes in assets and liabilities:		
Accounts receivable	(100,542)	18,375
Inventories	4,658	(10,212)
Prepaid expenses and other	(6,526)	2,952
Accounts payable trade	21,678	(21,661)
Revenues and royalties payable	12,920	4,477
Accrued liabilities and other	16,018	32,241
Other noncurrent assets and liabilities	5,839	(5)
Net cash provided by operating activities	1,156,945	770,830
Cash flows from investing activities		
Exploration and development	(1,823,215)	(1,778,808)
Purchase of producing crude oil and natural gas properties	(9,311)	(63,263)
Purchase of other property and equipment	(18,545)	(32,230)
Proceeds from sale of assets	894	100,809
Net cash used in investing activities	(1,850,177)	(1,773,492)
Cash flows from financing activities		
Revolving credit facility borrowings	440,000	1,239,000
Repayment of revolving credit facility	(1,035,000)	(1,060,000)
Proceeds from issuance of Senior Notes	1,479,375	787,000
Proceeds from other debt	—	22,000
Repayment of other debt	(969)	(628)
Debt issuance costs	(2,231)	(4,083)
Repurchase of equity grants	(3,259)	(5,094)
Exercise of stock options	—	60
Net cash provided by financing activities	877,916	978,255
Net change in cash and cash equivalents	184,684	(24,407)
Cash and cash equivalents at beginning of period	35,729	53,544
Cash and cash equivalents at end of period	$220,413	$29,137

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

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 properties 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 and the Red River units. The South region includes Kansas and all properties south of Kansas and west of the Mississippi River including the South Central Oklahoma Oil Province ("SCOOP"), Northwest Cana, and Arkoma Woodford plays in Oklahoma. The East region is comprised of undeveloped leasehold acreage east of the Mississippi River.
The Company's operations are geographically concentrated in the North region, with that region comprising approximately 77% of the Company's crude oil and natural gas production and approximately 87% of its crude oil and natural gas revenues for the six months ended June 30, 2013. The Company has focused its operations on the exploration and development of crude oil since the 1980s. For the six months ended June 30, 2013, crude oil accounted for approximately 71% of the Company's total production and approximately 88% 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 intercompany accounts and transactions have been eliminated upon consolidation. 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, 2012 ("2012 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, 2013 and for the three and six month periods ended June 30, 2013 and 2012 are unaudited. The condensed consolidated balance sheet as of December 31, 2012 was derived from the audited balance sheet included in the 2012 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 and estimation 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, 2013	December 31, 2012
Tubular goods and equipment	$12,326	$13,590
Crude oil	29,759	33,153
Total	$42,085	$46,743

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Continental Resources, Inc. and Subsidiaries
Notes to Unaudited Condensed Consolidated Financial Statements

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:

MBbls	June 30, 2013	December 31, 2012
Crude oil line fill requirements	398	391
Temporarily stored crude oil	97	211
Total	495	602

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, 2013 and 2012. All stock options issued by the Company in prior periods had been exercised or had expired as of March 31, 2012.

	Three months ended June 30,		Six months ended June 30,	
	2013	2012	2013	2012
In thousands, except per share data				
Income (numerator):				
Net income - basic and diluted	$323,270	$405,684	$463,897	$474,778
Weighted average shares (denominator):				
Weighted average shares - basic	184,039	179,781	184,019	179,744
Non-vested restricted stock	700	554	685	541
Stock options	—	—	—	32
Weighted average shares - diluted	184,739	180,335	184,704	180,317
Net income per share:				
Basic	$1.76	$2.26	$2.52	$2.64
Diluted	$1.75	$2.25	$2.51	$2.63

Adoption of new accounting standard

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 disclosure requirements became effective for periods beginning on or after January 1, 2013 and must be applied retrospectively to all periods presented on the balance sheet. The Company adopted the provisions of the new standard on January 1, 2013 and has included the required disclosures in Note 4. Derivative Instruments. Adoption of the new standard required additional footnote disclosures for the Company's derivative instruments and did not have an impact on its financial position, results of operations or cash flows.

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.

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Continental Resources, Inc. and Subsidiaries
Notes to Unaudited Condensed Consolidated Financial Statements

	Six months ended June 30,	
In thousands	2013	2012
Supplemental cash flow information:		
Cash paid for interest	$88,856	$38,567
Cash paid for income taxes	16,883	754
Cash received for income tax refunds	(173)	(72)
Non-cash investing activities:		
Increase in accrued capital expenditures	59,414	43,850
Asset retirement obligations, net	3,403	2,973

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 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.

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.

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, 2013, the Company had outstanding derivative contracts with respect to future production as set forth in the tables below.

Crude Oil - NYMEX WTI		Swaps	Collars Floors		Ceilings	
Period and Type of Contract	Bbls	Weighted Average Price	Range	Weighted Average Price	Range	Weighted Average Price
July 2013 - December 2013						
Swaps - WTI	5,796,000	$92.65				
Collars - WTI	4,416,000		$80.00 - $95.00	$86.92	$92.30 - $110.33	$99.46
January 2014 - December 2014						

Swaps - WTI	10,311,250	$96.20

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Continental Resources, Inc. and Subsidiaries
Notes to Unaudited Condensed Consolidated Financial Statements

Crude Oil - ICE Brent		Swaps	Collars Floors		Ceilings	
Period and Type of Contract	Bbls	Weighted Average Price	Range	Weighted Average Price	Range	Weighted Average Price
July 2013 - December 2013						
Swaps - ICE Brent	2,484,000	$108.72				
January 2014 - December 2014						
Swaps - ICE Brent	13,687,500	$102.52				
Collars - ICE Brent	2,190,000		$90.00 - $95.00	$90.83	$104.70 - $108.85	$107.13
January 2015 - December 2015						
Swaps - ICE Brent	1,277,500	$98.48				

Natural Gas - NYMEX Henry Hub

Period and Type of Contract	MMBtus	Swaps Weighted Average Price
July 2013 - December 2013		
Swaps - Henry Hub	46,000,000	$3.78
January 2014 - March 2014		
Swaps - Henry Hub	14,400,000	$4.30
April 2014 - December 2014		
Swaps - Henry Hub	30,250,000	$4.14

Derivative gains and losses

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,	
	2013	2012	2013	2012
In thousands				
Realized gain (loss) on derivatives:				
Crude oil fixed price swaps	$2,081	$(6,367)	$(7,512)	$(37,791)
Crude oil collars	254	(4,048)	379	(14,968)
Natural gas fixed price swaps	(7,087)	3,359	(4,429)	5,778
Realized loss on derivatives, net	$(4,752)	$(7,056)	$(11,562)	$(46,981)
Unrealized gain (loss) on derivatives:				
Crude oil fixed price swaps	$141,912	$329,545	$108,548	$248,547
Crude oil collars	15,968	158,053	2,206	99,110
Natural gas fixed price swaps	45,928	(8,814)	15,033	1,995
Unrealized gain on derivatives, net	$203,808	$478,784	$125,787	$349,652
Gain on derivative instruments, net	$199,056	$471,728	$114,225	$302,671

Balance sheet offsetting of derivative assets and liabilities

In December 2011, the FASB issued ASU No. 2011-11, Balance Sheet (Topic 210)–Disclosures about Offsetting Assets and Liabilities, which 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 Company adopted the provisions of the new standard on January 1, 2013 as required and has provided the applicable disclosures below with respect to its derivative instruments.

All of the Company’s derivative contracts are carried at their fair value in the condensed consolidated balance sheets under the captions “Derivative assets”, “Noncurrent derivative assets”, “Derivative liabilities”, and “Noncurrent derivative

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liabilities". Derivative assets and liabilities with the same counterparty that are subject to contractual terms which provide for net settlement are reported on a net basis in the condensed consolidated balance sheets.
The following tables present the gross amounts of recognized derivative assets and liabilities, the amounts offset under netting arrangements with counterparties, and the resulting net amounts presented in the condensed consolidated balance sheets for the periods presented, all at fair value.

	June 30, 2013			December 31, 2012		
In thousands	Gross amounts of recognized assets	Gross amounts offset on balance sheet	Net amounts of assets on balance sheet	Gross amounts of recognized assets	Gross amounts offset on balance sheet	Net amounts of assets on balance sheet
Commodity derivative assets	$185,882	$(17,838)	$168,044	$86,506	$(35,886)	$50,620

	June 30, 2013			December 31, 2012		
In thousands	Gross amounts of recognized liabilities	Gross amounts offset on balance sheet	Net amounts of liabilities on balance sheet	Gross amounts of recognized liabilities	Gross amounts offset on balance sheet	Net amounts of liabilities on balance sheet
Commodity derivative liabilities	$(8,285)	$1,476	$(6,809)	$(16,241)	$1,069	$(15,172)

The following table reconciles the net amounts disclosed above to the individual financial statement line items in the condensed consolidated balance sheets.

In thousands	June 30, 2013	December 31, 2012
Derivative assets	$76,478	$18,389
Noncurrent derivative assets	91,566	32,231
Net amounts of assets on balance sheet	$168,044	$50,620
Derivative liabilities	$(6,809)	$(12,999)
Noncurrent derivative liabilities	—	(2,173)
Net amounts of liabilities on balance sheet	$(6,809)	$(15,172)
Total derivative assets, net	$161,235	$35,448

Note 5. Fair Value Measurements
The Company follows a three-level valuation hierarchy for disclosure of fair value measurements. The valuation hierarchy categorizes assets and liabilities measured at fair value into one of three different levels depending on the observability of the inputs employed in the measurement. The three levels are defined as follows:

- Level 1: Observable inputs that reflect unadjusted quoted prices for identical assets or liabilities in active markets as of the reporting date.
- Level 2: Observable market-based inputs or unobservable inputs that are corroborated by market data. These are inputs other than quoted prices in active markets included in Level 1, which are either directly or indirectly observable as of the reporting date.
- Level 3: Unobservable inputs that are not corroborated by market data and may be used with internally developed methodologies that result in management's best estimate of fair value.

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

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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 market prices for forward commodity prices 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, 2013 and December 31, 2012.

	Fair value measurements at June 30, 2013 using:			
In thousands	Level 1	Level 2	Level 3	Total
Description				
Derivative assets (liabilities):				
Fixed price swaps	$—	$160,297	$—	$160,297
Collars	—	938	—	938
Total	$—	$161,235	$—	$161,235

	Fair value measurements at December 31, 2012 using:			
In thousands	Level 1	Level 2	Level 3	Total
Description				
Derivative assets (liabilities):				
Fixed price swaps	$—	$36,716	$—	$36,716
Collars	—	(1,268)	—	(1,268)
Total	$—	$35,448	$—	$35,448

Assets Measured at Fair Value on a Nonrecurring Basis

Certain assets 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.

Asset Impairments – Proved crude oil and natural gas properties are reviewed for impairment on a field-by-field basis each quarter, or 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 2017 (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%

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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.

At June 30, 2013 and 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 $39.6 million for the six months ended June 30, 2013, all of which was recognized in the second quarter. Such impairments primarily reflected uneconomic results for certain wells drilled on the Company's acreage in the Niobrara play in Colorado and Wyoming. The impaired properties were written down to their estimated fair value totaling approximately $22.2 million as of June 30, 2013. Impairment provisions for proved properties totaled $4.3 million for the three and six months ended June 30, 2012, primarily reflecting uneconomic results in a non-Woodford single-well field in the Company's South region. Those impaired properties were written down to their estimated fair value totaling approximately $2.2 million as of June 30, 2012.

Certain unproved crude oil and natural gas properties were impaired during the three and six months ended June 30, 2013 and 2012, reflecting recurring amortization of undeveloped leasehold costs on properties that management expects will not be transferred to proved properties over the lives of the leases based on experience of successful drilling and the average holding period.

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

	Three months ended June 30,		Six months ended June 30,	
	2013	2012	2013	2012
In thousands				
Proved property impairments	$39,635	$4,332	$39,635	$4,332
Unproved property impairments	40,077	31,539	80,158	61,446
Total	$79,712	$35,871	$119,793	$65,778

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.

	June 30, 2013		December 31, 2012	
In thousands	Carrying Amount	Fair Value	Carrying Amount	Fair Value
Debt:				
Revolving credit facility	$—	$—	$595,000	$595,000
Note payable	19,452	18,178	20,421	20,148
8 1/4% Senior Notes due 2019	298,192	327,750	298,085	339,000
7 3/8% Senior Notes due 2020	198,621	219,000	198,552	226,833
7 1/8% Senior Notes due 2021	400,000	438,700	400,000	454,333
5% Senior Notes due 2022	2,026,536	2,019,200	2,027,663	2,165,833
4 1/2% Senior Notes due 2023	1,500,000	1,455,000	—	—
Total debt	$4,442,801	$4,477,828	$3,539,721	$3,801,147

The fair value of any revolving credit facility borrowings approximates the 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.

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The fair values of the 8 1/4% Senior Notes due 2019 (“2019 Notes”), the 7 3/8% Senior Notes due 2020 (“2020 Notes”), the 7 1/8% Senior Notes due 2021 (“2021 Notes”), the 5% Senior Notes due 2022 (“2022 Notes”), and the 4 1/2% Senior Notes due 2023 ("2023 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:

In thousands	June 30, 2013	December 31, 2012
Revolving credit facility	$—	$595,000
Note payable	19,452	20,421
8 1/4% Senior Notes due 2019 (1)	298,192	298,085
7 3/8% Senior Notes due 2020 (2)	198,621	198,552
7 1/8% Senior Notes due 2021 (3)	400,000	400,000
5% Senior Notes due 2022 (4)	2,026,536	2,027,663
4 1/2% Senior Notes due 2023 (3)	1,500,000	—
Total debt	4,442,801	3,539,721
Less: Current portion of long-term debt	(1,981)	(1,950)
Long-term debt, net of current portion	$4,440,820	$3,537,771

(1) The carrying amount is net of unamortized discounts of $1.8 million and $1.9 million at June 30, 2013 and December 31, 2012, respectively.

(2) The carrying amount is net of unamortized discounts of $1.4 million at both June 30, 2013 and December 31, 2012.

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

(4) The carrying amount includes an unamortized premium of $26.5 million and $27.7 million at June 30, 2013 and December 31, 2012, respectively.

Revolving Credit Facility

On April 3, 2013, certain terms of the Company’s credit facility were amended. The amendment included, among other things, the following changes:

- Allows the Company to elect to suspend the need to comply with borrowing base requirements under the credit facility if either Moody’s or Standard & Poor’s (“S&P”) rates the Company’s senior unsecured debt at or above Ba1 (in the case of Moody’s) or BB+ (in the case of S&P). Previously, the credit facility required both Moody’s and S&P to provide those respective debt ratings before the Company could elect to suspend the borrowing base requirements.
- Allows the Company to elect to release the collateral consisting of crude oil and natural gas properties if either Moody’s or S&P rates the Company’s senior unsecured debt at or above Baa3 (in the case of Moody’s) or BBB- (in the case of S&P) (collectively, the “Collateral Release Ratings”), but requires the Company to continue certain reporting requirements and maintain a ratio of the Present Value, as defined in the amended credit facility, of the Company’s crude oil and natural gas properties to all funded debt of the Company of not less than 1.75 to 1.0 (the “Present Value Covenant”) during the period that only one of Moody’s or S&P has issued a rating at or above the Collateral Release Ratings. Previously, the credit facility required both Moody’s and S&P to rate the Company’s senior unsecured debt at or above the Collateral Release Ratings before the collateral from crude oil and natural gas properties could be released.
- Provides that if at least one of Moody’s or S&P has not rated the Company’s senior unsecured debt at or above the Collateral Release Ratings, the Company must provide an acceptable security interest in the lesser of (i) crude oil and

natural gas properties of the Company representing 80% of the Present Value of such properties and (ii) such of the Company's proved reserves and associated crude oil and natural gas properties sufficient to provide a Collateral Coverage Ratio, as defined in the amended credit facility, of at least 1.75 to 1.0.

- Provides that if both Moody's and S&P rate the Company's senior unsecured debt at or above the Collateral Release Ratings, the Company is not required to comply with certain reporting requirements and the Present Value Covenant. The Company will again be required to comply with such reporting requirements and the Present Value Covenant at such time as both Moody's and S&P do not rate the Company's senior unsecured debt at or above the Collateral Release Ratings.

The Company had no outstanding borrowings at June 30, 2013 on its credit facility, which matures on July 1, 2015. At December 31, 2012, the Company had $595.0 million of outstanding borrowings on its credit facility. The credit facility had aggregate commitments of $1.5 billion and a borrowing base of $4.25 billion at June 30, 2013, subject to semi-annual redetermination. The most recent borrowing base redetermination was completed in May 2013, whereby the lenders approved an increase in the Company's borrowing base from $3.25 billion to $4.25 billion. The terms of the facility allow for the commitment level to be increased up to the lesser of the borrowing base then in effect or $2.5 billion. Borrowings under the facility bear interest 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 150 to 250 basis points, depending on the percentage of the borrowing base utilized, or the lead bank's reference rate (prime) plus a margin ranging from 50 to 150 basis points.

The Company had approximately $1.5 billion of unused commitments under its credit facility at June 30, 2013 and incurs commitment fees of 0.375% per annum of the daily average amount of unused borrowing availability. The credit facility 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 4.0 to 1.0. As defined by the credit facility, the current ratio represents the 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 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, 2013.

Senior Notes

On April 5, 2013, the Company issued $1.5 billion of 4 1/2% Senior Notes due 2023 and received net proceeds of approximately $1.48 billion after deducting the initial purchasers' fees. The Company used a portion of the net proceeds from the offering to repay all borrowings then outstanding under its credit facility, which had a balance prior to payoff of approximately $1.04 billion, and has been using the remaining net proceeds to fund a portion of its 2013 capital budget and for general corporate purposes. The 2023 Notes will mature on April 15, 2023 and interest is payable on the 2023 Notes on April 15 and October 15 of each year, commencing October 15, 2013.

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 at June 30, 2013.

	2019 Notes	2020 Notes	2021 Notes	2022 Notes	2023 Notes
Maturity date	Oct 1, 2019	Oct 1, 2020	April 1, 2021	Sep 15, 2022	April 15, 2023
Interest payment dates	April 1, Oct. 1	April 1, Oct. 1	April 1, Oct. 1	March 15, Sept. 15	April 15, Oct. 15
Call premium redemption period (1)	Oct 1, 2014	Oct 1, 2015	April 1, 2016	March 15, 2017	n/a
Make-whole redemption period (2)	Oct 1, 2014	Oct 1, 2015	April 1, 2016	March 15, 2017	Jan 15, 2023
Equity offering redemption period (3)	—	Oct 1, 2013	April 1, 2014		n/a

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 optional redemption period for the 2019 Notes using equity offering proceeds expired on October 1, 2012.

The Company's senior notes are not subject to any mandatory redemption or sinking fund requirements.

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The Indentures, excluding the indenture governing the 2023 Notes, 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. The indenture governing the 2023 Notes is less restrictive and contains covenants that limit the Company's ability to create liens securing certain indebtedness and consolidate, merge or transfer certain assets. These covenants are subject to a number of important exceptions and qualifications. The Company was in compliance with these covenants at June 30, 2013. Two of the Company's subsidiaries, Banner Pipeline Company, L.L.C. and CLR Asset Holdings, LLC, which have insignificant assets with no current value and no operations, fully and unconditionally guarantee the senior notes. The Company's other subsidiary, 20 North Broadway Associates LLC, the value of whose assets and operations are minor, does not guarantee the senior notes.

Note Payable

In February 2012, 20 North Broadway Associates LLC, a wholly-owned subsidiary of the Company, borrowed $22 million under a 10-year amortizing term loan secured by the Company's corporate office building in Oklahoma City, Oklahoma. The loan bears interest at a fixed rate of 3.14% per annum. Principal and interest are payable monthly through the loan's maturity date of February 26, 2022. Accordingly, approximately $2.0 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, 2013.

Note 7. Commitments and Contingencies

Included below is a discussion of various future commitments of the Company as of June 30, 2013. The commitments under these arrangements are not recorded in the accompanying condensed consolidated balance sheets.

Drilling commitments – As of June 30, 2013, 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, 2013 total approximately $65 million, of which $48 million is expected to be incurred in the remainder of 2013 and $17 million in 2014.

Pipeline transportation commitments – The Company has entered into firm transportation commitments to guarantee pipeline access capacity totaling 15,000 barrels of crude oil per day on operational crude oil pipelines in order to reduce the impact of possible production curtailments that may arise due to limited transportation capacity. The commitments, which have 5-year terms extending as far as November 2017, require the Company to pay varying per-barrel transportation charges regardless of the amount of pipeline capacity used. Future commitments remaining as of June 30, 2013 under the operational crude oil pipeline transportation arrangements amount to approximately $50 million, of which $7 million is expected to be incurred in the remainder of 2013, $14 million in 2014, $14 million in 2015, $10 million in 2016 and $5 million in 2017.

The Company has also entered into a commitment to guarantee pipeline access capacity on an operational natural gas pipeline system to move a portion of its North region natural gas production to market. The commitment, which has a 10-year term ending in October 2023, requires the Company to pay per-unit transportation charges regardless of the amount of pipeline capacity used. Future commitments under the arrangement amount to approximately $25 million, which is expected to be incurred ratably over its 10-year term.

Further, the Company is a party to additional 5-year firm transportation commitments for future pipeline projects being considered for development that are not yet operational. Such projects require the granting of regulatory approvals or otherwise require significant additional construction efforts by the counterparties before being completed. Future commitments under the non-operational arrangements total approximately $1.0 billion at June 30, 2013, including approximately $96 million with an affiliate controlled by the Company's Chairman of the Board, Chief Executive Officer and principal shareholder. These commitments represent aggregate transportation charges expected to be incurred over the 5-year terms of the arrangements assuming the proposed pipeline projects are completed and become operational. The timing of the commencement of pipeline operations is not known due to uncertainties involving matters such as regulatory approvals, resolution of legal and environmental disputes, construction progress and the ultimate probability of pipeline completion. Accordingly, the timing of the Company's obligations under these non-operational arrangements cannot be predicted with certainty and may not be incurred on a ratable basis over a calendar year or may not be incurred at all. Although timing is uncertain, the Company's obligations under these arrangements are not expected to begin until at least 2014.

Rail transportation commitments – The Company has entered into firm transportation commitments to guarantee capacity on rail transportation facilities in order to reduce the impact of possible curtailments that may arise due to limited transportation capacity. The rail commitments have various terms extending through December 2014 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

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regardless of the amount of rail capacity used. Future commitments remaining as of June 30, 2013 under the rail transportation arrangements amount to approximately $27 million, of which $17 million is expected to be incurred in the remainder of 2013 and $10 million in 2014.

The Company’s pipeline and rail transportation commitments are for production primarily in the North region where the Company allocates a significant portion of its capital expenditures. The Company is not committed under these contracts 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 as categorized in the petition from crude oil and natural gas wells located in Oklahoma. The plaintiffs have alleged a number of claims, including breach of contract, fraud, breach of fiduciary duty, unjust enrichment, and other claims and 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 a reasonably possible loss or range of loss or what impact, if any, the action will have on its financial condition, results of operations or cash flows due to the preliminary status of the matter, the complexity and number of legal and factual issues presented by 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 class has not been certified. Plaintiffs have indicated that if the class is certified they may seek damages in excess of $165 million, a majority of which would be comprised of interest. The Company disputes plaintiffs’ claims, disputes that the case meets the requirements for a class action and is vigorously defending the case.

The Company is involved in various other legal proceedings such as commercial disputes, claims from royalty and surface owners, property damage claims, personal injury claims and similar matters. While the outcome of these legal matters cannot be predicted with certainty, the Company does not expect them to have a material effect on its financial condition, results of operations or cash flows. As of June 30, 2013 and December 31, 2012, the Company has recorded a liability in the condensed consolidated balance sheets under the caption “Other noncurrent liabilities” of $1.7 million and $2.4 million, respectively, for various matters, none of which are believed to be individually significant.

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

Note 8. Stock-Based Compensation

The Company has granted restricted stock to employees and directors pursuant to the Continental Resources, Inc. 2005 Long-Term Incentive Plan (“2005 Plan”) and 2013 Long-Term Incentive Plan ("2013 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,	
	2013	2012	2013	2012
In thousands				
Non-cash equity compensation	$9,756	$7,790	$18,998	$13,305

In May 2013, the Company's shareholders, upon recommendation by the Board of Directors, approved the adoption of the Company's 2013 Plan. The 2013 Plan is a broad-based incentive plan that allows the Company to use, if desired, a variety of equity compensation alternatives in structuring compensation arrangements for the Company's officers, directors and key employees. Effective May 23, 2013, the 2013 Plan replaced the Company's 2005 Plan as the instrument used to grant long-term incentive awards and no further awards will be granted under the 2005 Plan.

However, restricted stock awards granted under the 2005 Plan prior to the adoption of the 2013 Plan will remain outstanding in accordance with their terms.

The maximum number of shares of common stock available for issuance under the 2013 Plan will be 9,840,036 shares, which includes (i) 7,500,000 new shares authorized under the 2013 Plan, (ii) 1,840,036 shares that remained available for issuance under the 2005 Plan as of March 27, 2013 that have been transferred from the 2005 Plan to the 2013 Plan, and (iii) up to 500,000 shares available for issuance under the 2013 Plan to the extent such shares are forfeited or withheld for payment of income taxes related to existing awards outstanding under the 2005 Plan. As of June 30, 2013, the Company had a maximum of 9,829,816 shares of restricted stock available to grant to officers, directors and key employees under the 2013 Plan.

Restricted stock is awarded in the name of the recipient and constitutes issued and outstanding shares of the Company's common stock for all corporate purposes during the period of restriction and, except as otherwise provided under the 2013 Plan or agreement relevant to a given award, includes the right to vote the restricted stock or to receive dividends, subject to forfeiture. Restricted stock grants generally vest over periods ranging from one to three years.
A summary of changes in non-vested restricted stock shares outstanding for the six months ended June 30, 2013 is presented below:

	Number of non-vested shares	Weighted average grant-date fair value
Non-vested restricted shares outstanding at December 31, 2012	1,629,462	$63.28
Granted	129,850	83.94
Vested	(124,777)	60.65
Forfeited	(52,823)	72.47
Non-vested restricted shares outstanding at June 30, 2013	1,581,712	$67.52

The grant date fair value of restricted stock represents the closing market price 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, 2013 at the vesting date was approximately $10.4 million. As of June 30, 2013, there was approximately $62 million of unrecognized compensation expense related to non-vested restricted stock. This expense is expected to be recognized over a weighted average period of 1.6 years.

Note 9. 2012 Property Dispositions

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. 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 June 2012, the Company assigned certain non-strategic leaseholds and producing properties located in Oklahoma to a third party for $15.9 million and recognized a pre-tax gain on the transaction of $15.9 million. The disposed properties represented an immaterial portion of the Company's total proved reserves and production.

The gains on the above dispositions are included in the caption "(Gain) loss on sale of assets, net" in the unaudited condensed consolidated statements of income for the respective 2012 periods.

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 the condensed consolidated financial statements and notes thereto included elsewhere in this report and our historical consolidated financial statements and notes included in our Annual Report on Form 10-K for the year ended December 31, 2012. Our operating results for the periods discussed below 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, 2012, along with Cautionary Statement for the Purpose of the "Safe Harbor" Provisions of the Private Securities Litigation Reform Act of 1995 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 an independent crude oil and natural gas exploration and production company with properties 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, and the Red River units. The South region includes Kansas and all properties south of Kansas and west of the Mississippi River including the South Central Oklahoma Oil Province ("SCOOP"), Northwest Cana, and Arkoma Woodford plays in Oklahoma. The SCOOP and Northwest Cana plays were previously combined by us and referred to as the Anadarko Woodford play. The East region is comprised of undeveloped leasehold acreage east of the Mississippi River. Our operations are geographically concentrated in the North region, with that region comprising approximately 77% of our crude oil and natural gas production and approximately 87% of our crude oil and natural gas revenues for the six months ended June 30, 2013.

We focus our exploration activities in large new or developing crude oil and liquids-rich natural gas 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. In October 2012, we announced a five-year growth plan to triple our production and proved reserves from year-end 2012 to year-end 2017.

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.

2013 Highlights

Production, revenues and operating cash flows

For the second quarter of 2013, our crude oil and natural gas production averaged 135,700 Boe per day, representing a 12% increase over average daily production of 121,532 Boe per day for the first quarter of 2013 and a 43% increase over average daily production of 94,852 Boe per day for the second quarter of 2012. Crude oil and natural gas production averaged 128,655 Boe per day for the six months ended June 30, 2013, a 43% increase over average daily production of 90,189 Boe per day for the comparable 2012 period. Crude oil represented 71% of our total production for the three and six months ended June 30, 2013 compared to 69% for the three and six months ended June 30, 2012.

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The increase in 2013 production was primarily driven by higher production from our properties in the North Dakota Bakken field and the SCOOP play due to the continued success of our drilling programs in those areas.

Our Bakken production in North Dakota averaged 72,268 Boe per day for the first half of 2013, a 62% increase over the first half of 2012. Second quarter 2013 average daily production in North Dakota Bakken averaged 76,909 Boe per day, a 14% increase over the first quarter of 2013 and 63% higher than the second quarter of 2012.

Production in the emerging SCOOP play averaged 15,904 Boe per day for the first half of 2013, 447% higher than the comparable period in 2012. SCOOP average daily production totaled 17,547 Boe per day for the second quarter of 2013, an increase of 23% over the first quarter of 2013 and 435% higher than the 2012 second quarter.

Crude oil and natural gas revenues for the second quarter of 2013 increased 70% to $892.2 million primarily due to a 48% increase in sales volumes along with a 15% increase in realized commodity prices when compared to the second quarter of 2012. For the six months ended June 30, 2013, crude oil and natural gas revenues totaled $1.7 billion, a 56% increase from the comparable 2012 period, due to a 44% increase in sales volumes along with an 8% increase in realized commodity prices. Crude oil represented 87% and 88% of our total crude oil and natural gas revenues for the three and six months ended June 30, 2013, respectively, compared to 89% for both the three and six months ended June 30, 2012.

Cash flows from operating activities for the six months ended June 30, 2013 were $1,156.9 million, a 50% increase from $770.8 million provided by our operating activities during the comparable 2012 period. The increase in operating cash flows in 2013 was primarily due to increased crude oil and natural gas revenues driven by higher sales volumes and higher realized commodity prices coupled with lower realized losses on derivatives, partially offset by higher production expenses, production taxes, general and administrative expenses, and other expenses associated with the growth of our operations over the past year.

Capital expenditures

Our capital expenditures budget for 2013 is $3.6 billion, excluding acquisitions. For the six months ended June 30, 2013, we invested approximately $1.8 billion in our capital program, excluding $122.7 million of unbudgeted acquisitions and including $8.2 million of seismic costs and $59.4 million of capital costs associated with increased accruals for capital expenditures. Capital expenditures for the second quarter of 2013 totaled $896.9 million, excluding $100.7 million of unbudgeted acquisitions. Our 2013 capital program is focused primarily on increased exploration and development in the Bakken field of North Dakota and Montana and the SCOOP play in south-central Oklahoma. 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.

We hedge a portion of our anticipated future production to achieve more predictable cash flows and reduce our exposure to fluctuations in commodity prices. Reducing our exposure to price volatility helps ensure adequate funds are available for our capital program. We expect our cash flows from operations, our remaining cash balance, and our credit facility, including our ability to increase our borrowing capacity thereunder, will be sufficient to meet our budgeted capital expenditure needs for 2013; however, we may choose to access the capital markets for additional financing to take advantage of business opportunities that may arise if such financing can be arranged at favorable terms.

Issuance of new senior notes

On April 5, 2013, we issued $1.5 billion of 4 1/2% Senior Notes due 2023 (the “2023 Notes”) and received net proceeds of approximately $1.48 billion after deducting the initial purchasers’ fees. We used a portion of the net proceeds from the offering to repay all borrowings then outstanding under our credit facility, which had a balance prior to payoff of approximately $1.04 billion. The remaining net proceeds from the issuance of approximately $0.4 billion are being used to fund a portion of our 2013 capital budget and for general corporate purposes. The 2023 Notes will mature on April 15, 2023 and interest is payable on the 2023 Notes on April 15 and October 15 of each year, commencing October 15, 2013.

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Financial and operating highlights

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

- Volumes of crude oil and natural gas produced,
- Crude oil and natural gas prices realized,
- Per unit operating and administrative costs, and
- EBITDAX (a non-GAAP financial measure).

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

	Three months ended June 30,		Six months ended June 30,	
	2013	2012	2013	2012
Average daily production:				
Crude oil (Bbl per day)	96,029	65,274	91,077	62,587
Natural gas (Mcf per day)	238,028	177,471	225,467	165,611
Crude oil equivalents (Boe per day)	135,700	94,852	128,655	90,189
Average sales prices: (1)				
Crude oil ($/Bbl)	$87.22	$80.56	$88.50	$85.40
Natural gas ($/Mcf)	5.22	3.51	5.11	3.96
Crude oil equivalents ($/Boe)	71.13	61.69	71.68	66.31
Production expenses ($/Boe) (1)	5.86	5.16	5.79	5.17
General and administrative expenses ($/Boe) (1)	2.86	3.51	2.98	3.38
Net income (in thousands)	$323,270	$405,684	$463,897	$474,778
Diluted net income per share	$1.75	$2.25	$2.51	$2.63
EBITDAX (in thousands) (2)	708,107	421,860	1,329,635	876,392

(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, 2013 compared to the three months ended June 30, 2012

Results of Operations

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

	Three months ended June 30,	
	2013	2012
In thousands, except sales price data		
Crude oil and natural gas sales	$892,187	$523,393
Gain on derivative instruments, net (1)	199,056	471,728
Crude oil and natural gas service operations	9,509	9,598
Total revenues	1,100,752	1,004,719
Operating costs and expenses	526,880	318,245
Other expenses, net	60,744	30,902
Income before income taxes	513,128	655,572
Provision for income taxes	189,858	249,888
Net income	$323,270	$405,684
Production volumes:		
Crude oil (MBbl) (2)	8,739	5,940
Natural gas (MMcf)	21,661	16,150
Crude oil equivalents (MBoe)	12,349	8,632
Sales volumes:		
Crude oil (MBbl) (2)	8,932	5,793
Natural gas (MMcf)	21,661	16,150
Crude oil equivalents (MBoe)	12,542	8,485
Average sales prices: (3)		
Crude oil ($/Bbl)	$87.22	$80.56
Natural gas ($/Mcf)	5.22	3.51
Crude oil equivalents ($/Boe)	71.13	61.69

(1) Amounts include unrealized non-cash mark-to-market gains on derivatives of $203.8 million and $478.8 million for the three month periods ended June 30, 2013 and 2012, respectively.

(2) 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 193 MBbls more than crude oil production for the three months ended June 30, 2013 and 147 MBbls less than crude oil production for the three months ended June 30, 2012.

(3) 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, 2013 Volume	Percent	2012 Volume	Percent	Volume increase	Volume percent increase
Crude oil (MBbl)	8,739	71 %	5,940	69 %	2,799	47 %
Natural gas (MMcf)	21,661	29 %	16,150	31 %	5,511	34 %
Total (MBoe)	12,349	100 %	8,632	100 %	3,717	43 %

	Three months ended June 30, 2013 MBoe	Percent	2012 MBoe	Percent	Volume increase (decrease)	Volume percent increase (decrease)
North Region	9,557	77 %	6,406	74 %	3,151	49 %
South Region	2,792	23 %	2,129	25 %	663	31 %
East Region (1)	—	—	97	1 %	(97)	(100 %)
Total	12,349	100 %	8,632	100 %	3,717	43 %

(1) In December 2012, we sold the producing crude oil and natural gas properties in our East region and no new wells have been subsequently drilled in that region. Accordingly, no production is reflected for the East region for the three months ended June 30, 2013.

Crude oil production volumes increased 47% for the three months ended June 30, 2013 compared to the three months ended June 30, 2012. Production increases in the Bakken field and SCOOP play contributed incremental production volumes in 2013 of 3,010 MBbls, a 71% increase over production in these areas for the second quarter of 2012. Production growth in these areas is primarily due to increased drilling and completion activity resulting from our drilling program. These increases were partially offset by a decrease of 93 MBbls associated with non-strategic properties in the East region that were sold in December 2012. Additionally, production from our properties in the Red River units and Northwest Cana play decreased a total of 119 MBbls, or 8%, over the prior year second quarter due to a combination of natural declines in production and reduced drilling activity in those areas.

Natural gas production volumes increased 5,511 MMcf, or 34%, during the three months ended June 30, 2013 compared to the same period in 2012. Natural gas production in the Bakken field increased 3,227 MMcf, or 79%, for the three months ended June 30, 2013 compared to the same period in 2012 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 SCOOP play increased 5,350 MMcf, or 401%, due to additional wells being completed and producing in the three months ended June 30, 2013 compared to the same period in 2012. Further, natural gas production increased 336 MMcf, or 81%, in non-Bakken areas of our North region due to the completion of new wells subsequent to the 2012 second quarter. These increases were partially offset by decreases in production volumes totaling 3,373 MMcf, or 34%, from our properties in Northwest Cana, Arkoma Woodford, and non-core areas in our South region due to a combination of natural declines in production and reduced drilling activity prompted by the pricing environment for natural gas in those areas. For 2013, we are allocating a greater portion of our capital expenditures to crude oil and liquids-rich natural gas areas such as the Bakken field and SCOOP play and have temporarily deferred our drilling activity in the Northwest Cana and Arkoma Woodford plays, which typically contain higher concentrations of natural gas. Additionally, natural gas production decreased 26 MMcf associated with non-strategic properties in the East region that were sold in December 2012.

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, 2013 were $892.2 million, a 70% increase from sales of $523.4 million for the same period in 2012. Our sales volumes increased 4,057 MBoe, or 48%, over the comparable period in 2012 primarily due to the success of our drilling programs in the

North Dakota Bakken field and SCOOP play.

Our realized price per Boe increased $9.44 to $71.13 for the three months ended June 30, 2013 from $61.69 for the three months ended June 30, 2012. This increase reflects a significant improvement in crude oil differentials realized in the

2013 second quarter compared to the 2012 second quarter along with higher natural gas prices realized in connection with improved market prices.

The differential between NYMEX West Texas Intermediate ("WTI") calendar month average crude oil prices and our realized crude oil price per barrel for the three months ended June 30, 2013 decreased to $7.07 per barrel compared to $12.63 for the three months ended June 30, 2012 and $9.06 for the year ended December 31, 2012. The improved differential primarily reflects our shift to market and deliver our Bakken crude oil to higher-priced basis markets throughout the United States such as those on the gulf coast, east coast and west coast, with an increased reliance on rail transportation versus pipeline transportation, along with a general improvement in market differentials at conventional pipeline markets. During 2012, using rail transportation we increased our access to market centers on the east and west coasts of the United States and continued our marketing efforts along the U.S. gulf coast. This approach provided expanded flexibility that allowed us to shift sales of our Bakken crude oil to markets that provided us with more favorable pricing. Rail transportation costs are typically higher than pipeline transportation costs per barrel mile; however, the premium received during this period for our North region production sold in U.S. coastal markets compared to mid-continent WTI pricing more than offset the increased transportation costs. The positive effects of stronger pricing in coastal markets began to be realized in the fourth quarter of 2012 and continued into the first half of 2013. In recent months, the spread between mid-continent WTI pricing and pricing in U.S. coastal markets has narrowed. The narrowing of WTI and coastal market pricing could potentially have an adverse impact on our realized NYMEX WTI crude oil differentials if rail transportation continues to have a prominent role in our crude oil deliveries out of the North region and rail transportation costs are not reduced by pressure to compete with pipeline economics.

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. 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 on derivative instruments, net”, which is a component of total revenues.

Changes in commodity futures price strips during the second quarter of 2013 had a positive impact on the fair value of our derivatives, which resulted in positive revenue adjustments of $199.1 million for the three months ended June 30, 2013. 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,	
	2013	2012
In thousands		
Realized gain (loss) on derivatives:		
Crude oil derivatives	$2,335	$(10,415)
Natural gas derivatives	(7,087)	3,359
Realized loss on derivatives, net	$(4,752)	$(7,056)
Unrealized gain (loss) on derivatives:		
Crude oil derivatives	$157,880	$487,598
Natural gas derivatives	45,928	$(8,814)
Unrealized gain on derivatives, net	$203,808	$478,784
Gain on derivative instruments, net	$199,056	$471,728

The unrealized mark-to-market gains reflected above at June 30, 2013 relate to derivative instruments with various terms that are scheduled to be realized over the period from July 2013 to December 2015. Over this period, actual realized derivative settlements may differ significantly, either positively or negatively, from the unrealized mark-to-market valuation at June 30, 2013.

Operating Costs and Expenses

Production Expenses and Production Taxes and Other Expenses. Production expenses increased 68% to $73.4 million during the three months ended June 30, 2013 from $43.8 million during the three months ended June 30, 2012. This increase is primarily the result of higher production volumes from an increase in the number of producing wells coupled with higher costs incurred as a result of adverse weather conditions in the North region. Production expense per Boe was $5.86 for the three months ended June 30, 2013 compared to $5.16 per Boe for the three months ended June 30, 2012 and $5.49 per Boe for the year ended December 31, 2012. Contributing to the per-Boe increase were increases in well site and road maintenance costs and saltwater disposal costs resulting from a more severe winter season encountered in 2013, which created a more challenging operating environment compared to a mild winter season experienced in 2012. Adverse weather experienced in the North region for the first quarter of 2013 continued to impact operating conditions into April and May 2013 and resulted in higher per-Boe operating costs compared to the 2012 second quarter.

Production taxes and other expenses increased $33.0 million, or 67%, to $82.2 million during the three months ended June 30, 2013 compared to the three months ended June 30, 2012 primarily as a result of higher crude oil and natural gas revenues resulting from increased sales volumes and higher realized commodity prices. 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 $7.7 million and $6.6 million for the three months ended June 30, 2013 and 2012, respectively. The increase in other charges is primarily due to higher natural gas sales volumes in 2013. Production taxes, excluding other charges, as a percentage of crude oil and natural gas revenues were 8.3% for the three months ended June 30, 2013 compared to 8.1% for the three months ended June 30, 2012. 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. Some states offer exemptions or reduced production tax rates for wells that produce less than a certain quantity of crude oil or natural gas and to encourage certain activities, such as horizontal drilling and enhanced recovery projects. In Montana and Oklahoma, new horizontal wells qualify for a tax incentive and are taxed at a lower rate during their initial months of production. After the incentive period expires, the tax rate reverts to the statutory rate. Our overall production tax rate is expected to increase as we continue to grow 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:

	Three months ended June 30,	
$/Boe	2013	2012
Production expenses	$5.86	$5.16
Production taxes and other expenses	6.55	5.80
Production expenses, production taxes and other expenses	$12.41	$10.96

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	2013	2012
Geological and geophysical costs	$5,349	$8,692
Dry hole costs	5,802	10
Exploration expenses	$11,151	$8,702

Geological and geophysical costs decreased $3.3 million for the three months ended June 30, 2013 due to changes in the timing and amount of acquisitions of exploratory seismic data between periods. Dry hole charges recognized in the 2013 second quarter primarily reflect costs associated with exploratory wells in the Arkoma Woodford area of our South region.

Depreciation, Depletion, Amortization and Accretion (“DD&A”). Total DD&A increased $75.8 million, or 47%, in the second quarter of 2013 compared to the second quarter of 2012 primarily due to a 48% increase in sales volumes. The following table shows the components of our DD&A on a unit of sales basis.

	Three months ended June 30,	
$/Boe	2013	2012
Crude oil and natural gas	$18.61	$18.67
Other equipment	0.22	0.22

Asset retirement obligation accretion	0.05	0.09
Depreciation, depletion, amortization and accretion	$18.88	$18.98

Property Impairments. Property impairments increased in the three months ended June 30, 2013 by $43.8 million to $79.7 million compared to $35.9 million for the three months ended June 30, 2012.
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 $8.6 million during the three months ended June 30, 2013 to $40.1 million compared to $31.5 million for the three months ended June 30, 2012. The increase resulted from a larger base of amortizable costs in the current period coupled with higher rates of amortization resulting from changes in management's estimates of undeveloped properties not expected to be developed before lease expiration. We currently have no individually significant non-producing properties that are 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 using discounted cash flows. Impairments of proved properties amounted to $39.6 million for the three months ended June 30, 2013, primarily reflecting uneconomic results for certain wells drilled on the Company's acreage in the Niobrara play in Colorado and Wyoming. Proved property impairments totaled $4.3 million for the three months ended June 30, 2012, primarily reflecting uneconomic results in a non-Woodford single-well field in our South region.
General and Administrative Expenses. General and administrative expenses (“G&A”) increased $6.1 million, or 20%, to $35.9 million for the three months ended June 30, 2013 from $29.8 million for the comparable period in 2012. G&A expenses include non-cash charges for equity compensation of $9.8 million and $7.8 million for the three months ended June 30, 2013 and 2012, respectively. The increase in equity compensation in 2013 resulted primarily from larger grants of restricted stock being made throughout 2012 and 2013 due to employee growth, which resulted in increased expense recognition in the second quarter of 2013 compared to the second quarter of 2012.
The previously announced relocation of our corporate headquarters from Enid, Oklahoma to Oklahoma City was completed during 2012; however, residual costs continue to be incurred under the terms of the Company's relocation plan offered to employees. For the three months ended June 30, 2013, we recognized $0.7 million of costs associated with our relocation compared to $3.3 million for the three months ended June 30, 2012.
G&A expenses excluding equity compensation and relocation expenses increased $6.7 million for the three months ended June 30, 2013 compared to the same period in 2012. The increase was primarily due to an increase in personnel costs and office-related expenses associated with our rapid growth.
The following table shows the components of G&A expenses on a unit of sales basis for the periods presented. The decrease in G&A expenses on a per-unit basis in the 2013 second quarter was due in part to the rapid growth in our crude oil and natural gas sales volumes coupled with improved efficiency of operations compared to the prior year in which our corporate relocation was taking place.

	Three months ended June 30,	
$/Boe	2013	2012
General and administrative expenses	$2.03	$2.20
Non-cash equity compensation	0.78	0.92
Corporate relocation expenses	0.05	0.39
Total general and administrative expenses	$2.86	$3.51

Interest Expense. Interest expense increased $29.7 million, or 94%, to $61.4 million for the three months ended June 30, 2013 compared to $31.7 million for the three months ended June 30, 2012 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, 2013 was approximately $4.4 billion with a weighted average interest rate of 5.3% compared to a weighted average outstanding long-term debt balance of $2.1 billion and a weighted average interest rate of 5.5% for the comparable period in 2012. The increase in outstanding debt resulted from the issuance of $1.2 billion of 5% Senior Notes due 2022 in August 2012 and $1.5 billion of 2023 Notes in April 2013, the net proceeds of which were used to repay credit facility borrowings, to fund a portion of our capital budgets and for general corporate

purposes.
Our weighted average outstanding credit facility balance amounted to $84.9 million for the second quarter of 2013 compared to $397.2 million for the second quarter of 2012. The weighted average interest rate on our credit facility borrowings was 2.1% for the second quarter of 2013 compared to 2.2% for the same period in 2012. At June 30, 2013, we had no outstanding borrowings on our credit facility. We had $1.04 billion of outstanding borrowings on our credit facility at March

31, 2013. The decrease in credit facility borrowings in the 2013 second quarter resulted from paying off the outstanding balance in April 2013 using the net proceeds from the issuance of the 2023 Notes, with no subsequent credit facility borrowings.

Income Taxes. We recorded income tax expense for the three months ended June 30, 2013 of $189.9 million compared to $249.9 million for the three months ended June 30, 2012. We provided for income taxes at a combined federal and state tax rate of approximately 37% and 38% for the three months ended June 30, 2013 and 2012, respectively, after taking into account permanent taxable differences.

Six months ended June 30, 2013 compared to the six months ended June 30, 2012

Results of Operations

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

	Six months ended June 30,	
	2013	2012
In thousands, except sales price data		
Crude oil and natural gas sales	$1,675,704	$1,075,651
Gain on derivative instruments, net (1)	114,225	302,671
Crude oil and natural gas service operations	21,052	21,497
Total revenues	1,810,981	1,399,819
Operating costs and expenses	966,963	577,754
Other expenses, net	107,673	54,399
Income before income taxes	736,345	767,666
Provision for income taxes	272,448	292,888
Net income	$463,897	$474,778
Production volumes:		
Crude oil (MBbl) (2)	16,485	11,391
Natural gas (MMcf)	40,809	30,141
Crude oil equivalents (MBoe)	23,287	16,414
Sales volumes:		
Crude oil (MBbl) (2)	16,577	11,197
Natural gas (MMcf)	40,809	30,141
Crude oil equivalents (MBoe)	23,378	16,221
Average sales prices: (3)		
Crude oil ($/Bbl)	$88.50	$85.40
Natural gas ($/Mcf)	5.11	3.96
Crude oil equivalents ($/Boe)	71.68	66.31

(1) Amounts include unrealized non-cash mark-to-market gains on derivatives of $125.8 million and $349.7 million for the six months ended June 30, 2013 and 2012, respectively.

(2) 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 92 MBbls more than crude oil production for the six months ended June 30, 2013 and 194 MBbls less than crude oil production for the six months ended June 30, 2012.

(3) 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.

	Six months ended June 30, 2013 Volume	Percent	2012 Volume	Percent	Volume increase	Volume percent increase
Crude oil (MBbl)	16,485	71 %	11,391	69 %	5,094	45 %
Natural gas (MMcf)	40,809	29 %	30,141	31 %	10,668	35 %
Total (MBoe)	23,287	100 %	16,414	100 %	6,873	42 %

	Six months ended June 30, 2013 MBoe	Percent	2012 MBoe	Percent	Volume increase (decrease)	Volume percent increase (decrease)
North Region	17,949	77 %	12,311	75 %	5,638	46 %
South Region	5,338	23 %	3,898	24 %	1,440	37 %
East Region (1)	—	—	205	1 %	(205)	(100 %)
Total	23,287	100 %	16,414	100 %	6,873	42 %

(1) In December 2012, we sold the producing crude oil and natural gas properties in our East region and no new wells have been subsequently drilled in that region. Accordingly, no production is reflected for the East region for the six months ended June 30, 2013.

Crude oil production volumes increased 45% during the six months ended June 30, 2013 compared to the six months ended June 30, 2012. Production increases in the Bakken field and SCOOP play contributed incremental production volumes in 2013 of 5,516 MBbls, a 68% increase over production in these areas for the comparable period in 2012. Production growth in these areas is primarily due to increased drilling and completion activity resulting from our drilling program. These increases were partially offset by a decrease of 231 MBbls associated with non-strategic properties in Wyoming and the East region that were sold in February 2012 and December 2012, respectively. Additionally, production from our properties in the Red River units and Northwest Cana play decreased a total of 185 MBbls, or 6%, over the same period in 2012 due to a combination of natural declines in production and reduced drilling activity in those areas.

Natural gas production volumes increased 10,668 MMcf, or 35%, during the six months ended June 30, 2013 compared to the same period in 2012. Natural gas production in the Bakken field increased 5,426 MMcf, or 69%, for the six months ended June 30, 2013 compared to the same period in 2012 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 SCOOP play increased 9,743 MMcf, or 405%, due to additional wells being completed and producing in the six months ended June 30, 2013 compared to the same period in 2012. Further, natural gas production increased 487 MMcf, or 62%, in non-Bakken areas of our North region due to the completion of new wells during the 2013 period. These increases were partially offset by decreases in production volumes totaling 4,800 MMcf, or 27%, from our properties in Northwest Cana, Arkoma Woodford, and non-core areas in our South region due to a combination of natural declines in production and reduced drilling activity prompted by the pricing environment for natural gas in those areas. For 2013, we are allocating a greater portion of our capital expenditures to crude oil and liquids-rich natural gas areas such as the Bakken field and SCOOP play and have temporarily deferred our drilling activity in the Northwest Cana and Arkoma Woodford plays, which typically contain higher concentrations of natural gas. Additionally, natural gas production decreased 114 MMcf associated with non-strategic properties in Wyoming and the East region that were sold in February 2012 and December 2012, respectively.

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, 2013 were $1,675.7 million, a 56% increase from sales of $1,075.7 million for the same period in 2012. Our sales volumes increased 7,157 MBoe, or 44%, over the comparable period in 2012 primarily due to the success of our drilling programs in the North Dakota Bakken field and SCOOP play.

Our realized price per Boe increased $5.37 to $71.68 for the six months ended June 30, 2013 from $66.31 for the six months ended June 30, 2012. This increase reflects a significant improvement in crude oil differentials realized in the six months ended June 30, 2013 compared to the comparable 2012 period along with higher natural gas prices realized in connection with improved market prices.

The differential between NYMEX WTI calendar month average crude oil prices and our realized crude oil price per barrel for the six months ended June 30, 2013 decreased to $5.79 per barrel compared to $12.45 for the six months ended June 30, 2012 and $9.06 for the year ended December 31, 2012. The improved differential primarily reflects our shift to market and deliver our Bakken crude oil to higher-priced basis markets throughout the United States such as those on the gulf coast, east coast and west coast, with an increased reliance on rail transportation versus pipeline transportation, along with a general improvement in market differentials at conventional pipeline markets. During 2012, using rail transportation we increased our access to market centers on the east and west coasts of the United States and continued our marketing efforts along the U.S. gulf coast. This approach provided expanded flexibility that allowed us to shift sales of our Bakken crude oil to markets that provided us with more favorable pricing. Rail transportation costs are typically higher than pipeline transportation costs per barrel mile; however, the premium received during this period for our North region production sold in U.S. coastal markets compared to mid-continent WTI pricing more than offset the increased transportation costs. The positive effects of stronger pricing in coastal markets began to be realized in the fourth quarter of 2012 and continued into the first half of 2013. In recent months, the spread between mid-continent WTI pricing and pricing in U.S. coastal markets has narrowed. The narrowing of WTI and coastal market pricing could potentially have an adverse impact on our realized NYMEX WTI crude oil differentials if rail transportation continues to have a prominent role in our crude oil deliveries out of the North region and rail transportation costs are not reduced by pressure to compete with pipeline economics.

Derivatives. Changes in commodity futures price strips during the six months ended June 30, 2013 had a positive impact on the fair value of our derivatives, which resulted in positive revenue adjustments of $114.2 million for the six months ended June 30, 2013. 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.

	Six months ended June 30,	
	2013	2012
In thousands		
Realized gain (loss) on derivatives:		
Crude oil derivatives	$(7,133)	$(52,759)
Natural gas derivatives	(4,429)	5,778
Realized loss on derivatives, net	$(11,562)	$(46,981)
Unrealized gain (loss) on derivatives:		
Crude oil derivatives	$110,754	$347,657
Natural gas derivatives	15,033	$1,995
Unrealized gain on derivatives, net	$125,787	$349,652
Gain on derivative instruments, net	$114,225	$302,671

The unrealized mark-to-market gains reflected above at June 30, 2013 relate to derivative instruments with various terms that are scheduled to be realized over the period from July 2013 to December 2015. Over this period, actual realized derivative settlements may differ significantly, either positively or negatively, from the unrealized mark-to-market valuation at June 30, 2013.

Operating Costs and Expenses

Production Expenses and Production Taxes and Other Expenses. Production expenses increased 61% to $135.2 million during the six months ended June 30, 2013 from $83.8 million during the six months ended June 30, 2012. This increase is primarily the result of higher production volumes from an increase in the number of producing wells coupled with higher costs incurred as a result of adverse weather conditions in the North region. Production expense per Boe was $5.79 for the six months ended June 30, 2013 compared to $5.17 per Boe for the six months ended June 30, 2012 and $5.49 per Boe for the year ended December 31, 2012. Contributing to the per-Boe increase were increases in well site and road maintenance costs and saltwater disposal costs resulting from a more severe winter season encountered in 2013, which created a more challenging operating environment compared to a mild winter season experienced in 2012. Adverse weather experienced in the North region for the first quarter of 2013 continued to impact operating conditions into April and May 2013 and resulted in higher per-Boe operating costs compared to 2012.

Production taxes and other expenses increased $54.7 million, or 55%, to $154.7 million during the six months ended June 30, 2013 compared to the six months ended June 30, 2012 primarily as a result of higher crude oil and natural gas revenues resulting from increased sales volumes and higher realized commodity prices. 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 $15.3 million and $12.0 million for the six months ended June 30, 2013 and 2012, respectively. The increase in other charges is primarily due to higher natural gas sales volumes in 2013. Production taxes, excluding other charges, as a percentage of crude oil and natural gas revenues were 8.3% for the six months ended June 30, 2013 compared to 8.1% for the six months ended June 30, 2012. 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 increase as we continue to grow 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:

	Six months ended June 30,	
$/Boe	2013	2012
Production expenses	$5.79	$5.17
Production taxes and other expenses	6.61	6.16
Production expenses, production taxes and other expenses	$12.40	$11.33

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. Dry hole charges recognized in 2013 primarily reflect costs associated with exploratory wells in the Arkoma Woodford area and a non-Woodford area of our South region.

	Six months ended June 30,	
In thousands	2013	2012
Geological and geophysical costs	$12,902	$12,755
Dry hole costs	8,063	98
Exploration expenses	$20,965	$12,853

Depreciation, Depletion, Amortization and Accretion. Total DD&A increased $140.0 million, or 45%, in the six months ended June 30, 2013 compared to the same period in 2012 primarily due to a 44% increase in sales volumes. The following table shows the components of our DD&A on a unit of sales basis.

	Six months ended June 30,	
$/Boe	2013	2012
Crude oil and natural gas	$18.99	$18.79
Other equipment	0.22	0.26
Asset retirement obligation accretion	0.06	0.09
Depreciation, depletion, amortization and accretion	$19.27	$19.14

Property Impairments. Property impairments increased in the six months ended June 30, 2013 by $54.0 million to $119.8 million compared to $65.8 million for the six months ended June 30, 2012.

Impairments of non-producing properties increased $18.8 million during the six months ended June 30, 2013 to $80.2 million compared to $61.4 million for the six months ended June 30, 2012. The increase resulted from a larger base of amortizable costs in the current period coupled with higher rates of amortization resulting from changes in management's estimates of undeveloped properties not expected to be developed before lease expiration. We currently have no individually significant non-producing properties that are assessed for impairment on a property-by-property basis.

Impairment provisions for proved properties were $39.6 million for the six months ended June 30, 2013, primarily reflecting uneconomic results for certain wells drilled on the Company's acreage in the Niobrara play in Colorado and Wyoming. Impairment provisions for proved properties was $4.3 million for the six months ended June 30, 2012, primarily reflecting uneconomic results in a non-Woodford single-well field in our South region.

General and Administrative Expenses. G&A expenses increased $14.9 million, or 27%, to $69.7 million for the six months ended June 30, 2013 from $54.8 million for the comparable period in 2012. G&A expenses include non-cash charges

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for equity compensation of $19.0 million and $13.3 million for the six months ended June 30, 2013 and 2012 respectively. The increase in equity compensation in 2013 resulted primarily from larger grants of restricted stock being made throughout 2012 and 2013 due to employee growth, which resulted in increased expense recognition in the six months ended June 30, 2013 compared to the six months ended June 30, 2012.

The previously announced relocation of our corporate headquarters from Enid, Oklahoma to Oklahoma City was completed during 2012; however, residual costs continue to be incurred under the terms of the Company's relocation plan offered to employees. For the six months ended June 30, 2013, we recognized $1.4 million of costs associated with our relocation compared to $5.1 million for the six months ended June 30, 2012.

G&A expenses excluding equity compensation and relocation expenses increased $12.9 million for the six months ended June 30, 2013 compared to the same period in 2012. The increase was primarily due to an increase in personnel costs and office-related expenses associated with our rapid growth.

The following table shows the components of G&A expenses on a unit of sales basis for the periods presented. The decrease in G&A expenses on a per-unit basis in 2013 was due in part to the rapid growth in our crude oil and natural gas sales volumes coupled with improved efficiency of operations compared to the prior year in which our corporate relocation was taking place.

	Six months ended June 30,	
$/Boe	2013	2012
General and administrative expenses	$2.11	$2.25
Non-cash equity compensation	0.81	0.82
Corporate relocation expenses	0.06	0.31
Total general and administrative expenses	$2.98	$3.38

Interest Expense. Interest expense increased $52.9 million, or 94%, to $108.9 million for the six months ended June 30, 2013 compared to $56.0 million for the six months ended June 30, 2012 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, 2013 was approximately $4.1 billion with a weighted average interest rate of 5.1% compared to a weighted average outstanding long-term debt balance of $1.9 billion and a weighted average interest rate of 5.6% for the comparable period in 2012. The increase in outstanding debt resulted from the issuance of $1.2 billion of 5% Senior Notes due 2022 in August 2012 and $1.5 billion of 2023 Notes in April 2013, the net proceeds of which were used to repay credit facility borrowings, to fund a portion of our capital budgets and for general corporate purposes. For the six months ended June 30, 2013, our weighted average outstanding credit facility balance amounted to $448.4 million compared to $434.3 million for the six months ended June 30, 2012. The weighted average interest rate on our credit facility borrowings was 1.9% for the six months ended June 30, 2013 compared to 2.3% for the same period in 2012. At June 30, 2013, we had no outstanding borrowings on our credit facility. We had $595.0 million of outstanding borrowings on our credit facility at December 31, 2012, which subsequently increased to $1.04 billion at March 31, 2013 before being paid off in April 2013 using the net proceeds from the issuance of the 2023 Notes.

Income Taxes. We recorded income tax expense for the six months ended June 30, 2013 of $272.4 million compared to $292.9 million for the six months ended June 30, 2012. We provided for income taxes at a combined federal and state tax rate of approximately 37% and 38% for the six months ended June 30, 2013 and 2012, respectively, after taking into account permanent taxable differences.

Liquidity and Capital Resources

Our primary sources of liquidity have been cash flows generated from operating activities, financing provided by our revolving credit facility and the issuance of debt and equity securities. As of June 30, 2013, we had $220.4 million of cash and cash equivalents and approximately $1.5 billion of borrowing availability on our credit facility. No borrowings were outstanding on our credit facility at June 30, 2013. As of August 1, 2013, we continued to have approximately $1.5 billion of borrowing availability on our credit facility with no borrowings outstanding.

Cash Flows

Cash flows from operating activities

Our net cash provided by operating activities was $1,156.9 million and $770.8 million for the six months ended June 30, 2013 and 2012, respectively. The increase in operating cash flows was primarily due to higher crude oil and natural gas

revenues driven by higher sales volumes and higher realized commodity prices coupled with lower realized losses on derivatives, which were partially offset by 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, 2013 and 2012, we had cash flows used in investing activities (excluding asset sales) of $1,851.1 million and $1,874.3 million, respectively, related to our capital program, inclusive of dry hole costs and property acquisitions. Acquisition capital expenditures totaled $122.7 million and $362.3 million for the six months ended June 30, 2013 and 2012, respectively. In the first half of 2012 we executed a transaction to acquire properties in North Dakota for $276 million, with no individual transactions of that size occurring in the first half of 2013. Capital expenditures excluding acquisitions totaled $1,728.4 million and $1,512.0 million for the six months ended June 30, 2013 and 2012, respectively, the increase of which was driven by an increase in our capital budget for 2013.

The use of cash for capital expenditures during the six months ended June 30, 2012 was partially offset by proceeds received from asset dispositions. Proceeds from the sale of assets amounted to $100.8 million for the six months ended June 30, 2012, primarily related to our February 2012 disposition of certain Wyoming properties for proceeds of $84.4 million and our June 2012 disposition of certain Oklahoma properties for proceeds of $15.9 million. No significant asset dispositions occurred during the six months ended June 30, 2013.

Cash flows from financing activities

Net cash provided by financing activities for the six months ended June 30, 2013 was $877.9 million, primarily resulting from the receipt of $1.48 billion of net proceeds from the issuance of $1.5 billion of 4 1/2% Senior Notes due 2023 (the "2023 Notes") in April 2013, partially offset by net repayments of $595.0 million on our credit facility.

Net cash provided by financing activities of $978.3 million for the six months ended June 30, 2012 was the result of receiving $787.0 million of net proceeds from our March 2012 issuance of $800 million of 5% Senior Notes due 2022 along with 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.

Future Sources of Financing

Although we cannot provide any assurance, assuming sustained 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, including our ability to increase our borrowing capacity thereunder, 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 for the next 12 months. We may choose to access the capital markets for additional financing to take advantage of business opportunities that may arise if such financing can be arranged at favorable terms.

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.

Revolving credit facility

We have a credit facility which has aggregate lender commitments totaling $1.5 billion and a borrowing base of $4.25 billion, subject to semi-annual redetermination. The most recent borrowing base redetermination was completed in May 2013, whereby the lenders approved an increase in the borrowing base from $3.25 billion to $4.25 billion. The aggregate commitment level may be increased from time to time (provided no default exists) up to the lesser of $2.5 billion or the borrowing base then in effect. Borrowings under the credit facility bear interest at a rate per annum equal to the London Interbank Offered Rate (LIBOR) for one, two, three or six months, as elected by us, plus a margin ranging from 150 to 250 basis points, depending on the percentage of the borrowing base utilized, or the lead bank’s reference rate (prime) plus a margin ranging from 50 to 150 basis points.

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 no outstanding borrowings and approximately $1.5 billion of borrowing availability on our credit facility at June 30, 2013. On April 5, 2013, we issued $1.5 billion of 2023 Notes and received net proceeds of approximately $1.48 billion after deducting the initial purchasers' fees. The net proceeds were used to repay all borrowings then outstanding under our credit facility, which had a balance prior to payoff of approximately $1.04 billion. At August 1, 2013, we continued to have no outstanding borrowings and approximately $1.5 billion of borrowing availability on our credit facility.

Our credit facility contains restrictive covenants that may limit our ability to, among other things, incur additional indebtedness, sell assets, make loans to others, make investments, enter into mergers, change material contracts, incur liens and engage in certain other transactions without the prior consent of the lenders. Our credit facility also contains requirements that we maintain a current ratio of not less than 1.0 to 1.0 and a ratio of total funded debt to EBITDAX of no greater than 4.0 to 1.0. As defined by our credit facility, 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 revolving 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, 2013 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 or increase their commitments to the borrowing base amount. We expect the next borrowing base redetermination to occur in the fourth quarter of 2013. 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 on acceptable terms when needed, 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.

Proceeds from issuance of long-term debt

As discussed above, we used a portion of the $1.48 billion of net proceeds from our April 5, 2013 issuance of the 2023 Notes to repay all borrowings then outstanding under our credit facility, which had a balance prior to payoff of approximately $1.04 billion. The remaining net proceeds from the issuance of approximately $0.4 billion are being used to fund a portion of our 2013 capital budget and for general corporate purposes.

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. Refer to 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, 2013 and the estimated fair value of those contracts as of that date. We expect to continue entering into derivative instruments covering a portion of our future crude oil and/or natural gas production in order to further secure cash flows in support of our growth plans; however, we may choose not to hedge future production if the pricing environment for certain time periods is not deemed to be favorable.

Future Capital Requirements

Senior note maturities

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	2023 Notes
Maturity date	Oct 1, 2019	Oct 1, 2020	April 1, 2021	Sep 15, 2022	April 15, 2023
Interest payment dates	April 1, Oct. 1	April 1, Oct. 1	April 1, Oct. 1	March 15, Sept. 15	April 15, Oct. 15
Call premium redemption period (1)	Oct 1, 2014	Oct 1, 2015	April 1, 2016	March 15, 2017	n/a
Make-whole redemption period (2)	Oct 1, 2014	Oct 1, 2015	April 1, 2016	March 15, 2017	Jan 15, 2023
Equity offering redemption period (3)	—	Oct 1, 2013	April 1, 2014	March 15, 2015	n/a

(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 or amounts 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. The optional redemption period for the 2019 Notes using equity offering proceeds expired on October 1, 2012.

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, excluding the indenture governing the 2023 Notes, 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. The indenture governing the 2023 Notes is less restrictive and contains covenants that limit our ability to create liens securing certain indebtedness and consolidate, merge or transfer certain assets. These covenants are subject to a number of important exceptions and qualifications. We were in compliance with these covenants as of June 30, 2013 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. Two of our subsidiaries, Banner Pipeline Company, L.L.C. and CLR Asset Holdings, LLC, which have insignificant assets with no current value and no operations, fully and unconditionally guarantee the senior notes. Our other subsidiary, 20 Broadway Associates LLC, the value of whose assets and operations are minor, does not guarantee the senior notes.

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.

In October 2012, we announced a five-year growth plan to triple our production and proved reserves from year-end 2012 to year-end 2017. Our capital expenditures budget for 2013 is $3.6 billion excluding acquisitions, which is expected to be allocated as follows.

	Amount

In millions	
Exploration and development drilling	$3,155
Land costs	220
Capital facilities, workovers and re-completions	175
Buildings, vehicles, computers and other equipment	30
Seismic	20
Total	$3,600

During the six months ended June 30, 2013, we participated in the completion of 418 gross (169.9 net) wells and invested approximately $1,795.8 million in our capital program, excluding $122.7 million of unbudgeted acquisitions and including $8.2 million of seismic costs and $59.4 million of capital costs associated with increased accruals for capital expenditures. Our 2013 year-to-date capital expenditures were as follows.

In millions	Amount
Exploration and development drilling	$1,585.0
Land costs	154.3
Capital facilities, workovers and re-completions	29.9
Buildings, vehicles, computers and other equipment	18.4
Seismic	8.2
Capital expenditures, excluding acquisitions	$1,795.8
Acquisitions of producing properties	9.3
Acquisitions of non-producing properties	113.4
Total acquisitions	$122.7
Total capital expenditures	$1,918.5

Although we cannot provide any assurance, assuming sustained 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, including our ability to increase our borrowing capacity thereunder, will be sufficient to fund the remainder of our 2013 capital program; however, we may choose to access the capital markets for additional financing to take advantage of business opportunities that may arise if such financing can be arranged at favorable terms. 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, unbudgeted acquisitions, actual drilling results, the availability of drilling rigs and other services and equipment, changes in commodity prices, and regulatory, technological and competitive developments. We expect to continue participating as a buyer of properties when and if we have the ability to increase our position in strategic plays at favorable terms.

Commitments

Following is a discussion of various future commitments of the Company as of June 30, 2013. The commitments under these arrangements are not recorded in the accompanying condensed consolidated balance sheets.

Drilling commitments – As of June 30, 2013, 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. Future drilling commitments as of June 30, 2013 total approximately $65 million, of which $48 million is expected to be incurred in the remainder of 2013 and $17 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.

Pipeline transportation commitments – We have entered into firm transportation commitments to guarantee pipeline access capacity totaling 15,000 barrels of crude oil per day on operational crude oil pipelines in order to reduce the impact of possible production curtailments that may arise due to limited transportation capacity. The commitments, which have 5-year terms extending as far as November 2017, require us to pay varying per-barrel transportation charges regardless of the amount of pipeline capacity used. Future commitments remaining as of June 30, 2013 under the operational pipeline transportation arrangements amount to approximately $50 million, of which $7 million is expected to be incurred in the remainder of 2013, $14 million in 2014, $14 million in 2015, $10 million in 2016 and $5 million in 2017.

We have also entered into a commitment to guarantee pipeline access capacity on an operational natural gas pipeline system to move a portion of our North region natural gas production to market. The commitment, which has a 10-year term ending in October 2023, requires us to pay per-unit transportation charges regardless of the amount of pipeline capacity used. Future commitments under the arrangement amount to approximately $25 million, which is expected to be incurred ratably over its 10-year term.

Further, we are a party to additional 5-year firm transportation commitments for future pipeline projects being considered for development that are not yet operational. Such projects require the granting of regulatory approvals or otherwise require significant additional construction efforts by our counterparties before being completed. Future commitments under the non-operational arrangements total approximately $1.0 billion at June 30, 2013, including approximately $96 million with an affiliate controlled by our Chairman of the Board, Chief Executive Officer and principal shareholder. These commitments represent aggregate transportation charges expected to be incurred over the 5-year terms of the arrangements assuming the proposed pipeline projects are completed and become operational. The timing of the commencement of pipeline operations is not known due to uncertainties involving matters such as regulatory approvals, resolution of legal and environmental disputes, construction progress and the ultimate probability of pipeline completion. Accordingly, the timing of our obligations under these non-operational arrangements cannot be predicted with certainty and may not be incurred on a ratable basis over a calendar year or may not be incurred at all. Although timing is uncertain, our obligations under these arrangements are not expected to begin until at least 2014.

Rail transportation commitments – We have entered into firm transportation commitments to guarantee capacity on rail transportation facilities in order to reduce the impact of possible curtailments that may arise due to limited transportation capacity. The rail commitments have various terms extending through December 2014 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 regardless of the amount of rail capacity used. Future commitments remaining as of June 30, 2013 under the rail transportation arrangements amount to approximately $27 million, of which $17 million is expected to be incurred in the remainder of 2013 and $10 million in 2014.

Our pipeline and rail transportation commitments are for production primarily in the North region where we allocate a significant portion of our capital expenditures. We are not committed under these 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, including our ability to increase our borrowing capacity thereunder, will be sufficient to satisfy the above commitments.

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, 2012.

Recent Accounting Pronouncements Not Yet Adopted

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 2013 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

We use a variety of financial and operational measures to assess our performance. Among these measures is EBITDAX. 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. Our credit facility requires that we maintain a total funded debt to EBITDAX ratio of no greater than 4.0 to 1.0 on a rolling four-quarter basis. This ratio represents the sum of outstanding borrowings and letters of credit under our credit facility plus our note payable and senior note obligations, divided by total

EBITDAX for the most recent four quarters. We were in compliance with this covenant at June 30, 2013. 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	2013	2012	2013	2012
Net income	$323,270	$405,684	$463,897	$474,778
Interest expense	61,378	31,691	108,853	55,969
Provision for income taxes	189,858	249,888	272,448	292,888
Depreciation, depletion, amortization and accretion	236,790	161,018	450,468	310,473
Property impairments	79,712	35,871	119,793	65,778
Exploration expenses	11,151	8,702	20,965	12,853
Impact from derivative instruments:				
Total gain on derivatives, net	(199,056)	(471,728)	(114,225)	(302,671)
Total realized loss (cash flow) on derivatives, net	(4,752)	(7,056)	(11,562)	(46,981)
Non-cash gain on derivatives, net	(203,808)	(478,784)	(125,787)	(349,652)
Non-cash equity compensation	9,756	7,790	18,998	13,305
EBITDAX	$708,107	$421,860	$1,329,635	$876,392

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,	
In thousands	2013	2012
Net cash provided by operating activities	$1,156,945	$770,830
Current income tax provision	5,830	2,150
Interest expense	108,853	55,969
Exploration expenses, excluding dry hole costs	12,902	12,755
Gain (loss) on sale of assets, net	(213)	67,024
Other, net	(637)	(6,169)
Changes in assets and liabilities	45,955	(26,167)
EBITDAX	$1,329,635	$876,392

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, 2013, and excluding any effect of our derivative instruments in place, our annual revenue would increase or decrease by approximately $332 million for each $10.00 per barrel change in crude oil prices and $82 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.

Changes in commodity futures price strips during the six months ended June 30, 2013 had an overall positive impact on the fair value of our derivative instruments. For the six months ended June 30, 2013, we reported an unrealized non-cash mark-to-market gain on derivatives of $125.8 million which was partially offset by realized net losses on derivatives of $11.6 million. The fair value of our derivative instruments at June 30, 2013 was a net asset of $161.2 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 2013 through December 2015. Over this period, actual realized derivative settlements may differ significantly, either positively or negatively, from the unrealized mark-to-market valuation at June 30, 2013. An assumed increase in the forward commodity prices used in the June 30, 2013 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 $302 million at June 30, 2013. 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 $614 million at June 30, 2013.

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 ($599.9 million in receivables at June 30, 2013), our joint interest receivables ($339.7 million at June 30, 2013), and counterparty credit risk associated with our derivative instrument receivables ($168.0 million at June 30, 2013).

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 $48.0 million at June 30, 2013, 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 no outstanding borrowings under our credit facility at August 1, 2013.

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, 2013. 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 three months ended June 30, 2013, 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.

PART II. Other Information

ITEM 1. Legal Proceedings

During the six months ended June 30, 2013 there have been no material changes with respect to the legal proceedings previously disclosed in our 2012 Form 10-K that was filed with the SEC on February 28, 2013. See Note 7. Commitments and Contingencies in Notes to Unaudited Condensed Consolidated Financial Statements included elsewhere in this report.

ITEM 1A. Risk Factors

There have been no material changes in our risk factors from those disclosed in our 2012 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 2012 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 2012 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) Recent Sales of Unregistered Securities – Not applicable.

(b) Use of Proceeds – Not applicable.

(c) Purchases of Equity Securities by the Issuer and Affiliated Purchasers – The following table provides information about purchases of equity securities registered by the Company pursuant to Section 12 of the Exchange Act during the three months ended June 30, 2013:

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 programs (3)
April 1, 2013 to April 30, 2013	—	$—	—	—
May 1, 2013 to May 31, 2013	21,020	$83.93	—	—
June 1, 2013 to June 30, 2013	—	$—	—	—
Total	21,020	$83.93	—	—

(1) In connection with restricted stock grants under the Company's 2005 Long-Term Incentive Plan ("2005 Plan") and 2013 Long-Term Incentive Plan ("2013 Plan"), we adopted a policy that enables employees to surrender shares to cover their tax liability. Effective May 23, 2013, the 2013 Plan was adopted and replaced the Company's 2005 Plan. Restricted stock awards granted under the 2005 Plan prior to the adoption of the 2013 Plan will remain outstanding in accordance with their terms. 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 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.

ITEM 3. Defaults Upon Senior Securities

Not applicable.

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.

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 7, 2013	By: /s/ John D. Hart John D. Hart Sr. Vice President, Chief Financial Officer and Treasurer (Duly Authorized Officer and Principal Financial Officer)

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	Third Amended and Restated Bylaws of Continental Resources, Inc. filed as Exhibit 3.1 to the Company's Current Report on Form 8-K (Commission File No. 001-32886) filed November 6, 2012 and incorporated herein by reference.
4.1	Indenture dated as of April 5, 2013 among Continental Resources, Inc., Banner Pipeline Company, L.L.C., CLR Asset Holdings, LLC and Wilmington Trust, National Association, as trustee, filed as Exhibit 4.1 to the Company's Current Report on Form 8-K (Commission File No. 001-32886) filed April 11, 2013 and incorporated herein by reference.
4.2	Registration Rights Agreement dated as of April 5, 2013 among Continental Resources, Inc., Banner Pipeline Company, L.L.C., CLR Asset Holdings, LLC and Merrill Lynch, Pierce, Fenner & Smith Incorporated as the representative of the several initial purchasers, filed as Exhibit 4.2 to the Company's Current Report on Form 8-K (Commission File No. 001-32886) filed April 11, 2013 and incorporated herein by reference.
10.1	Purchase Agreement dated as of April 2, 2013 among Continental Resources, Inc., Banner Pipeline Company, L.L.C., CLR Asset Holdings, LLC and Merrill Lynch, Pierce, Fenner & Smith Incorporated as representative of the several initial purchasers filed as Exhibit 10.1 to the Company's Current Report on Form 8-K (Commission File No. 001-32886) filed April 3, 2013 and incorporated herein by reference.
10.2	Amendment No. 2 dated April 3, 2013 to the Seventh Amended and Restated Credit Agreement dated June 30, 2010, among Continental Resources, Inc., as borrower, Banner Pipeline Company L.L.C. and CLR Asset Holdings, LLC as guarantors, Union Bank, N.A., as administrative agent and issuing lender, and the other lenders party thereto filed as Exhibit 10.1 to the Company's Current Report on Form 8-K (Commission File No. 001-32886) filed April 5, 2013 and incorporated herein by reference.
10.3†	Continental Resources, Inc. 2013 Long-Term Incentive Plan included as Appendix A to the Company's Definitive Proxy Statement on Schedule 14A (Commission File No. 001-32886) filed April 10, 2013 and incorporated herein by reference.
10.4†	Form of Employee Restricted Stock Award Agreement under the Continental Resources, Inc. 2013 Long-Term Incentive Plan filed as Exhibit 10.2 to the Company's Current Report on Form 8-K (Commission File No. 001-32886) filed May 24, 2013 and incorporated herein by reference.
10.5†	Form of Non-Employee Director Restricted Stock Award Agreement under the Continental Resources, Inc. 2013 Long-Term Incentive Plan filed as Exhibit 10.3 to the Company's Current Report on Form 8-K (Commission File No. 001-32886) filed May 24, 2013 and incorporated herein by reference.
10.6*†	Summary of Non-Employee Director Compensation Approved as of May 23, 2013 to be effective July 1, 2013.
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
† Management contract or compensatory plan or arrangement filed pursuant to Item 601(b)(10)(iii) of Regulation S-K.