CONTINENTAL RESOURCES INC
Form 10-Q
August 05, 2011
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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, 2011

or

¨ **TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**
For the transition period from ______ to ______

Commission File Number: 001-32886

CONTINENTAL RESOURCES, INC.

(Exact name of registrant as specified in its charter)

Oklahoma	**73-0767549**
(State or other jurisdiction of incorporation or organization)	**(I.R.S. Employer Identification No.)**
302 N. Independence, Suite 1500, Enid, Oklahoma	**73701**
(Address of principal executive offices)	**(Zip Code)**

Registrant s telephone number, including area code: (580) 233-8955

Former name, former address and former fiscal year, if changed since last report: Not applicable

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

180,525,143 shares of our $0.01 par value common stock were outstanding on July 31, 2011.

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

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Glossary of Crude Oil and Natural Gas Terms

The terms defined in this section are used throughout this report.

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

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

Bopd Barrels of crude oil per day.

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

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

DD&A Depreciation, depletion, amortization and accretion.

Developed acreage The number of acres that are allocated or assignable to productive wells or wells capable of production.

Development well A well drilled within the proved area of a crude oil or natural gas reservoir to the depth of a stratigraphic horizon known to be productive.

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

Enhanced recovery The recovery of crude oil and natural gas through the injection of liquids or gases into the reservoir. Enhanced recovery methods are often applied when production slows due to depletion of the natural pressure.

Exploratory well A well drilled to find a new field or to find a new reservoir in a field previously found to be productive of crude oil or natural gas in another reservoir.

Field An area consisting of a single reservoir or multiple reservoirs all grouped on, or related to, the same individual geological structural feature or stratigraphic condition. The field name refers to the surface area, although it may refer to both the surface and the underground productive formations.

Formation A layer of rock which has distinct characteristics that differ from nearby rock.

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

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

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

MBoe One thousand Boe.

Mcf One thousand cubic feet of natural gas.

MMBtu One million British thermal units. A British thermal unit represents the amount of energy needed to heat one pound of water by one degree Fahrenheit and can be used to describe the energy content of fuels.

MMcf One million cubic feet of natural gas.

NYMEX The New York Mercantile Exchange.

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

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

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

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

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

Reservoir A porous and permeable underground formation containing a natural accumulation of producible crude oil and/or natural gas that is confined by impermeable rock or water barriers and is separate from other reservoirs.

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

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

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

Unit The joining of all or substantially all interests in a reservoir or field, rather than a single tract, to provide for development and operation without regard to separate property interests. Also, the area covered by a unitization agreement.

Working interest The right granted to the lessee of a property to explore for and to produce and own crude oil, natural gas, or other minerals. The working interest owners bear the exploration, development, and operating costs on either a cash, penalty, or carried basis.

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Cautionary Statement Regarding Forward-Looking Statements

Certain statements and information in this report may constitute forward-looking statements within the meaning of the Private Securities Litigation Reform Act of 1995. All statements other than statements of historical fact included in this report are forward-looking statements. When used in this report, the words could, may, believe, anticipate, intend, estimate, expect, project and similar expressions are inte identify forward-looking statements, although not all forward-looking statements contain such identifying words. Forward-looking statements are based on the Company s current expectations and assumptions about future events and currently available information as to the outcome and timing of future events. When considering forward-looking statements, you should keep in mind the risk factors and other cautionary statements described under the heading *Item 1A. Risk Factors* included in this report and in our Annual Report on Form 10-K for the year ended December 31, 2010.

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

Forward-looking statements may include statements about:

- our business strategy;
- our future operations;
- our reserves;
- our technology;
- our financial strategy;
- crude oil and natural gas prices;
- the timing and amount of future production of crude oil and natural gas;
- the amount, nature and timing of capital expenditures;
- estimated revenues and results of operations;
- drilling of wells;
- competition;
- marketing of crude oil and natural gas;

- exploitation or property acquisitions;
- costs of exploiting and developing our properties and conducting other operations;
- our financial position;
- general economic conditions;
- credit markets;
- our liquidity and access to capital;
- the impact of regulatory and legal proceedings involving us and of scheduled or potential regulatory changes;
- our future operating results; and
- plans, objectives, expectations and intentions contained in this report that are not historical.

We caution you that these forward-looking statements are subject to all of the risks and uncertainties, most of which are difficult to predict and many of which are beyond our control, incident to the exploration for, and development, production, and sale of, crude oil and natural gas. These risks include, but are not limited to, commodity price volatility, inflation, lack of availability of drilling and production equipment and services, environmental risks, drilling and other operating risks, regulatory changes, the uncertainty inherent in estimating crude oil and natural gas reserves and in projecting future rates of production, cash flows and access to capital, the timing of development expenditures, and the other risks described under *Part II, Item 1A. Risk Factors* in this report, our Annual Report on Form 10-K for the year ended December 31, 2010, registration statements filed from time to time with the SEC, and other announcements we make from time to time.

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

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

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PART I. Financial Information

ITEM 1. Financial Statements

Continental Resources, Inc. and Subsidiaries

Condensed Consolidated Balance Sheets

	June 30, 2011 *(Unaudited)*	December 31, 2010
	In thousands, except par values and share data	
Assets		
Current assets:		
Cash and cash equivalents	$ 261,408	$ 7,916
Receivables:		
Crude oil and natural gas sales	264,668	208,211
Affiliated parties	22,562	20,156
Joint interest and other, net	325,309	254,471
Derivative assets	13,700	21,365
Inventories	50,840	38,362
Deferred and prepaid taxes	44,199	22,672
Prepaid expenses and other	8,815	9,173
Total current assets	991,501	582,326
Net property and equipment, based on successful efforts method of accounting	3,635,046	2,981,991
Debt issuance costs, net	25,535	27,468
Noncurrent derivative assets	289	
Total assets	$ 4,652,371	$ 3,591,785
Liabilities and shareholders equity		
Current liabilities:		
Accounts payable trade	$ 441,305	$ 390,892
Revenues and royalties payable	177,025	133,051
Payables to affiliated parties	6,632	4,438
Accrued liabilities and other	111,857	94,829
Derivative liabilities	119,273	76,771
Current portion of asset retirement obligations	2,464	2,241
Total current liabilities	858,556	702,222
Long-term debt	896,141	925,991
Other noncurrent liabilities:		
Deferred income tax liabilities	664,518	582,841
Asset retirement obligations, net of current portion	56,228	54,079
Noncurrent derivative liabilities	195,818	112,940
Other noncurrent liabilities	5,422	5,557
Total other noncurrent liabilities	921,986	755,417
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; 180,526,914 shares issued and outstanding at June 30, 2011; 170,408,652 shares issued and outstanding at December 31, 2010		1,805		1,704
Additional paid-in capital		1,105,339		439,900
Retained earnings		868,544		766,551
Total shareholders equity		1,975,688		1,208,155
Total liabilities and shareholders equity	$	4,652,371	$	3,591,785

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,	
	2011	2010	2011	2010
	In thousands, except per share data			
Revenues:				
Crude oil and natural gas sales	$ 378,388	$ 211,204	$ 695,128	$ 419,263
Crude oil and natural gas sales to affiliates	10,396	8,222	20,123	17,287
Gain (loss) on derivative instruments, net	204,453	55,465	(164,850)	81,809
Crude oil and natural gas service operations	9,655	5,077	16,281	9,877
Total revenues	602,892	279,968	566,682	528,236
Operating costs and expenses:				
Production expenses	31,444	21,259	59,842	40,418
Production expenses to affiliates	917	1,089	1,789	4,531
Production taxes and other expenses	33,491	18,231	61,053	34,238
Exploration expenses	5,034	2,269	11,846	4,055
Crude oil and natural gas service operations	8,064	4,091	13,515	8,047
Depreciation, depletion, amortization and accretion	83,501	58,822	159,151	111,409
Property impairments	19,242	19,514	40,090	34,689
General and administrative expenses	17,209	11,494	33,556	23,343
Gain on sale of assets	(318)	(33,124)	(15,575)	(33,346)
Total operating costs and expenses	198,584	103,645	365,267	227,384
Income from operations	404,308	176,323	201,415	300,852
Other income (expense):				
Interest expense	(18,785)	(11,903)	(37,756)	(20,263)
Other	1,022	78	1,531	784
	(17,763)	(11,825)	(36,225)	(19,479)
Income before income taxes	386,545	164,498	165,190	281,373
Provision for income taxes	147,351	62,757	63,197	107,167
Net income	$ 239,194	$ 101,741	$ 101,993	$ 174,206
Basic net income per share	$ 1.33	$ 0.60	$ 0.58	$ 1.03
Diluted net income per share	$ 1.33	$ 0.60	$ 0.58	$ 1.03

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

	Shares outstanding	Common stock	Additional paid-in capital	Retained earnings	Total shareholders equity
		In thousands, except share data			
Balance, December 31, 2010	170,408,652	$ 1,704	$ 439,900	$ 766,551	$ 1,208,155
Net income (unaudited)				101,993	101,993
Public offering of common stock (unaudited)	10,080,000	101	659,131		659,232
Stock-based compensation (unaudited)			7,497		7,497
Stock options:					
Exercised (unaudited)	12,470		9		9
Repurchased and canceled (unaudited)	(2,495)		(150)		(150)
Restricted stock:					
Issued (unaudited)	59,740				
Repurchased and canceled (unaudited)	(16,153)		(1,048)		(1,048)
Forfeited (unaudited)	(15,300)				
Balance, June 30, 2011	180,526,914	$ 1,805	$ 1,105,339	$ 868,544	$ 1,975,688

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, 2011	Six months ended June 30, 2010
Cash flows from operating activities:	*In thousands*	
Net income	$ 101,993	$ 174,206
Adjustments to reconcile net income to net cash provided by operating activities:		
Depreciation, depletion, amortization and accretion	161,184	111,417
Property impairments	40,090	34,689
Change in fair value of derivatives	132,756	(64,714)
Stock-based compensation	7,497	5,970
Provision for deferred income taxes	62,237	95,500
Dry hole costs	3,370	409
Gain on sale of assets	(15,575)	(33,346)
Other, net	1,799	2,746
Changes in assets and liabilities:		
Accounts receivable	(129,701)	(104,885)
Inventories	(12,478)	(12,507)
Prepaid expenses and other	(1,665)	2,387
Accounts payable trade	16,712	153,063
Revenues and royalties payable	43,974	13,053
Accrued liabilities and other	16,779	11,065
Other noncurrent liabilities	(6)	1,172
Net cash provided by operating activities	428,966	390,225
Cash flows from investing activities:		
Exploration and development	(797,414)	(469,484)
Purchase of crude oil and natural gas properties	(149)	(151)
Purchase of other property and equipment	(28,837)	(14,261)
Proceeds from sale of assets	22,784	21,332
Net cash used in investing activities	(803,616)	(462,564)
Cash flows from financing activities:		
Revolving credit facility borrowings	135,000	169,000
Repayment of revolving credit facility	(165,000)	(281,000)
Proceeds from issuance of Senior Notes		194,210
Proceeds from issuance of common stock	659,736	
Debt issuance costs	(37)	(7,876)
Equity issuance costs	(368)	
Repurchase of equity grants	(1,198)	(985)
Dividends to shareholders		(3)
Exercise of stock options	9	3
Net cash provided by financing activities	628,142	73,349
Net change in cash and cash equivalents	253,492	1,010
Cash and cash equivalents at beginning of period	7,916	14,222
Cash and cash equivalents at end of period	$ 261,408	$ 15,232

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

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Continental Resources, Inc. and Subsidiaries

Notes to Unaudited Condensed Consolidated Financial Statements

Note 1. Organization and Nature of Business

Description of the Company

Continental s principal business is crude oil and natural gas exploration, development and production with operations in the North, South, and East regions of the United States. The North region consists of properties north of Kansas and west of the Mississippi river and includes North Dakota Bakken, Montana Bakken, the Red River units and the Niobrara play in Colorado and Wyoming. The South region includes Kansas and all properties south of Kansas and west of the Mississippi river including the Anadarko Woodford and Arkoma Woodford plays in Oklahoma. The East region consists of properties east of the Mississippi river including the Illinois Basin and the state of Michigan.

Note 2. Basis of Presentation and Significant Accounting Policies

Basis of presentation

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

This report has been prepared pursuant to the rules and regulations of the Securities and Exchange Commission (SEC) applicable to interim financial information. Because this is an interim period filing presented using a condensed format, it does not include all of the disclosures required by accounting principles generally accepted in the United States (U.S. GAAP), although the Company believes that the disclosures are adequate to make the information not misleading. You should read this Form 10-Q along with the Company s Annual Report on Form 10-K for the year ended December 31, 2010 (2010 Form 10-K), which includes a summary of the Company s significant accounting policies and other disclosures.

The financial statements as of June 30, 2011 and for the three and six month periods ended June 30, 2011 and 2010 are unaudited. The condensed consolidated balance sheet as of December 31, 2010 was derived from the audited balance sheet filed in the 2010 Form 10-K. The Company has evaluated events or transactions through the date this report on Form 10-Q was filed with the SEC in conjunction with its preparation of these financial statements.

The preparation of financial statements in conformity with U.S. GAAP requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities, the disclosure of contingent assets and liabilities at the date of the financial statements, and the reported amounts of revenues and expenses during the reporting period. Actual results could differ from those estimates. The most significant of the estimates and assumptions that affect reported results is the estimate of the Company s crude oil and natural gas reserves, which is used to compute depreciation, depletion, amortization and impairment on producing crude oil and natural gas properties. In the opinion of management, all adjustments (consisting only of normal recurring adjustments) necessary for a fair presentation in accordance with U.S. GAAP have been included in these 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, 2011**	**December 31, 2010**
Tubular goods and equipment	$ 20,632	$ 16,306
Crude oil	30,208	22,056
Total	$ 50,840	$ 38,362

Crude oil inventories, including line fill, 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:

In barrels	June 30, 2011	December 31, 2010
Crude oil line fill requirements	390,000	257,000
Temporarily stored crude oil	144,000	148,000
Total	534,000	405,000

Continental Resources, Inc. and Subsidiaries

Notes to Unaudited Condensed Consolidated Financial Statements

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 dilutive stock options, which are calculated using the treasury stock method as if the awards and options were exercised. The following is the calculation of basic and diluted weighted average shares outstanding and net income per share for the three and six months ended June 30, 2011 and 2010:

	Three months ended June 30,		Six months ended June 30,	
	2011	2010	2011	2010
	In thousands, except per share data			
Income (numerator):				
Net income - basic and diluted	$ 239,194	$ 101,741	$ 101,993	$ 174,206
Weighted average shares (denominator):				
Weighted average shares - basic	179,424	168,887	175,598	168,872
Nonvested restricted stock	707	744	703	704
Employee stock options	98	301	99	302
Weighted average shares - diluted	180,229	169,932	176,400	169,878
Net income per share:				
Basic	$ 1.33	$ 0.60	$ 0.58	$ 1.03
Diluted	$ 1.33	$ 0.60	$ 0.58	$ 1.03

Recent accounting pronouncements

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

In June 2011, the FASB issued ASU No. 2011-05, *Comprehensive Income (Topic 220) Presentation of Comprehensive Income.* ASU No. 2011-05 is intended to improve the quality of financial reporting by increasing the prominence of items reported in other comprehensive income (OCI). Under ASU No. 2011-05, an entity will have the option to present the components of net income, the components of other comprehensive income, and the total of comprehensive income either in a single continuous statement of comprehensive income or in two separate but consecutive statements. Companies will no longer be allowed to present OCI in the statement of stockholders equity. The amendments do not change the items that must be reported in OCI nor do they affect how earnings per share is calculated or presented. For public entities, the new standard is effective for fiscal years, and interim periods within those years, beginning after December 15, 2011 and is required to be applied retrospectively. The Company will adopt the requirements of ASU No. 2011-05 on January 1, 2012, which is not currently expected to have an effect on its financial reporting as the Company currently has no items of OCI.

Note 3. Supplemental Cash Flow Information

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

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Continental Resources, Inc. and Subsidiaries

Notes to Unaudited Condensed Consolidated Financial Statements

	Six months ended June 30, 2011	2010
	In thousands	
Supplemental cash flow information:		
Cash paid for interest	$ 35,658	$ 15,742
Cash paid for income taxes	$ 3,164	$ 5,804
Cash received for income tax refunds	$ (116)	$ (1,288)
Non-cash investing activities:		
Asset retirement obligations	$ 1,071	$ 697

Note 4. Derivative Instruments

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

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

During the six months ended June 30, 2011, the Company entered into several new swap and collar derivative contracts covering a portion of its crude oil and natural gas production for 2011, 2012 and 2013. The new contracts were entered into in the ordinary course of business and the Company may enter into additional similar contracts during the year. None of the new contracts have been designated for hedge accounting.

With respect to a fixed price swap contract, the counterparty is required to make a payment to the Company if the settlement price for any settlement period is less than the swap price, and the Company is required to make a payment to the counterparty if the settlement price for any settlement period is greater than the swap price. For a basis swap contract, which guarantees a price differential between the NYMEX prices and the Company s physical pricing points, the Company receives a payment from the counterparty if the settled price differential is greater than the stated terms of the contract and the Company pays the counterparty if the settled price differential is less than the stated terms of the contract. 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 payment to the counterparty if the settlement price for any settlement period is above the ceiling price, and neither party is required to make a payment to the other party if the settlement price for any settlement period is between the floor price and the ceiling price.

All of the Company s derivative contracts are carried at their fair value on the condensed consolidated balance sheets under the captions Derivative assets , Noncurrent derivative assets , Derivative liabilities , and Noncurrent derivative liabilities . Derivative assets and liabilities with the same counterparty and subject to contractual terms which provide for net settlement are reported on a net basis on the condensed consolidated balance sheets. Substantially all of the crude oil and natural gas derivative contracts are settled based upon reported prices on the NYMEX. The estimated fair value of these contracts is based upon various factors, including closing exchange prices on the NYMEX, 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*.

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Continental Resources, Inc. and Subsidiaries

Notes to Unaudited Condensed Consolidated Financial Statements

At June 30, 2011, the Company had outstanding contracts with respect to future production as set forth in the tables below.

Crude Oil

			Collars			
		Swaps	Floors		Ceilings	
Period and Type of Contract	Bbls	Weighted Average	Range	Weighted Average	Range	Weighted Average
July 2011 - September 2011						
Swaps	460,000	$ 85.64				
Collars	2,622,000		$ 75.00-$80.00	$ 79.39	$ 89.00-$97.25	$ 91.27
October 2011 - December 2011						
Swaps	644,000	$ 86.25				
Collars	2,622,000		$ 75.00-$80.00	$ 79.39	$ 89.00-$97.25	$ 91.27
January 2012 - December 2012						
Swaps	9,150,000	$ 90.17				
Collars	5,332,620		$ 80.00	$ 80.00	$ 93.25-$97.00	$ 94.71
January 2013 - December 2013						
Swaps	5,110,000	$ 88.63				
Collars	8,760,000		$ 80.00-$95.00	$ 86.92	$ 92.30-$110.33	$ 99.46

Natural Gas

Period and Type of Contract	MMBtus	Swaps Weighted Average
July 2011 - September 2011		
Swaps	6,900,000	$ 5.42
October 2011 - December 2011		
Swaps	7,222,000	$ 5.40
January 2012 - December 2012		
Swaps	3,660,000	$ 5.07

Derivative Fair Value Gain (Loss)

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

	Three months ended June 30, 2011	Three months ended June 30, 2010	Six months ended June 30, 2011	Six months ended June 30, 2010
	In thousands			
Realized gain (loss) on derivatives:				
Crude oil fixed price swaps	$ (4,881)	$ 4,898	$ (7,976)	$ 7,430
Crude oil collars	(29,394)	1,059	(39,641)	1,059
Natural gas fixed price swaps	7,397	7,534	15,523	10,255
Natural gas basis swaps		(688)		(1,649)
Unrealized gain (loss) on derivatives				

Crude oil fixed price swaps	87,179	13,023	(77,864)	10,811
Crude oil collars	147,572	39,634	(47,516)	35,085
Natural gas fixed price swaps	(3,420)	(11,031)	(7,376)	17,294
Natural gas basis swaps		1,036		1,524
Gain (loss) on derivative instruments, net	$ 204,453	$ 55,465	$ (164,850)	$ 81,809

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The table below provides data about the fair value of derivatives that are not accounted for using hedge accounting.

	June 30, 2011			December 31, 2010		
In thousands	Assets Fair Value	(Liabilities) Fair Value	Net Fair Value	Assets Fair Value	(Liabilities) Fair Value	Net Fair Value
Commodity swaps and collars	$ 13,989	$ (315,091)	$ (301,102)	$ 21,365	$ (189,711)	$ (168,346)

Note 5. Fair Value Measurements

The Company is required to calculate fair value based on a hierarchy which prioritizes the inputs to valuation techniques used to measure fair value into three levels. The fair value hierarchy gives the highest priority to unadjusted quoted market prices in active markets for identical assets or liabilities (Level 1) and the lowest priority to unobservable inputs (Level 3). Level 2 inputs are inputs, other than quoted prices included within Level 1, which are observable for the asset or liability, either directly or indirectly. As Level 1 inputs generally provide the most reliable evidence of fair value, the Company uses Level 1 inputs when available.

Assets and Liabilities Measured at Fair Value on a Recurring Basis

Certain assets and liabilities are reported at fair value on a recurring basis. The Company s assessment of the significance of a particular input to the fair value measurement requires judgment, and may affect the valuation of the fair value of assets and liabilities and their placement within the fair value hierarchy levels. In determining the fair value of fixed price swaps and basis swaps, due to the unavailability of relevant comparable market data for the Company s exact contracts, a discounted cash flow method is used. The discounted cash flow method estimates future cash flows based on quoted market prices for future commodity prices, observable inputs relating to basis differentials and a risk-adjusted discount rate. The fair value of fixed price swaps and basis swap derivatives is calculated using mainly significant observable inputs (Level 2). The calculation of the fair value of collar contracts requires the use of an option-pricing model with significant unobservable inputs (Level 3). The valuation model for option derivative contracts is an industry-standard model that considers various inputs including: (a) quoted forward prices for commodities, (b) time value, (c) volatility factors, and (d) current market and contractual prices for the underlying instruments, as well as other relevant economic measures. The 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, 2011 and December 31, 2010. There were no transfers between Level 1 and Level 2 of the fair value hierarchy during the six months ended June 30, 2011. Further, there were no transfers in and/or out of Level 3 of the fair value hierarchy during the six months ended June 30, 2011.

	December 31,	December 31,	December 31,	December 31,
	Fair value measurements at June 30, 2011 using:			
Description	**Level 1**	**Level 2**	**Level 3**	**Total**
		In thousands		
Derivative assets (liabilities):				
Fixed price swaps	$	$ (150,169)	$	$ (150,169)
Collars			(150,933)	(150,933)
Total	$	$ (150,169)	$ (150,933)	$ (301,102)

	Fair value measurements at December 31, 2010 using:			
Description	**Level 1**	**Level 2**	**Level 3**	**Total**

			In thousands					
Derivative assets (liabilities):								
Fixed price swaps	$		$	(64,928)	$		$	(64,928)
Collars						(103,418)		(103,418)
Total	$		$	(64,928)	$	(103,418)	$	(168,346)

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Notes to Unaudited Condensed Consolidated Financial Statements

The following table sets forth a reconciliation of changes in the fair value of financial assets and liabilities classified as Level 3 in the fair value hierarchy for the indicated periods:

	2011	2010
	In thousands	
Balance at January 1	$ (103,418)	$ (3,275)
Total realized or unrealized gains (losses), net:		
Included in earnings	(195,088)	(4,549)
Included in other comprehensive income		
Purchases		
Sales		
Issuances		
Settlements		
Transfers into Level 3		
Transfers out of Level 3		
Balance at March 31	$ (298,506)	$ (7,824)
Total realized or unrealized gains (losses), net:		
Included in earnings	147,573	39,634
Included in other comprehensive income		
Purchases		
Sales		
Issuances		
Settlements		
Transfers into Level 3		
Transfers out of Level 3		
Balance at June 30	$ (150,933)	$ 31,810
Change in unrealized gains (losses) relating to derivatives still held at June 30	$ (49,102)	$ 35,271

Gains and losses included in earnings for the three and six month periods ended June 30, 2011 and 2010 attributable to the change in unrealized gains and losses relating to derivatives held at June 30, 2011 and 2010 are reported in Revenues Gain (loss) on derivative instruments, net .

Assets and Liabilities Measured at Fair Value on a Nonrecurring Basis

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

Asset Impairments Proved crude oil and natural gas properties are reviewed for impairment when events and circumstances indicate a possible decline in the recoverability of the carrying value of such property. The estimated future cash flows expected in connection with the property are compared to the carrying amount of the property to determine if the carrying amount is recoverable. If the carrying amount of the property exceeds its estimated undiscounted future cash flows, the carrying amount of the property 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).

Non-producing crude oil and natural gas properties, which primarily consist of undeveloped leasehold costs and costs associated with the purchase of proved undeveloped reserves, are assessed for impairment on a property-by-property basis for individually significant balances, if any, and on an aggregate basis by prospect for individually insignificant balances. If the assessment indicates an impairment, a loss is recognized by providing a valuation allowance at the level consistent with the level at which impairment was

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assessed. The impairment assessment is affected by economic factors such as the results of exploration activities, commodity price outlooks, remaining lease terms, and potential shifts in business strategy employed by management. For individually insignificant non-producing properties, the amount of the impairment loss recognized is determined by amortizing the portion of the properties costs which management estimates will not be transferred to proved properties over the life of the lease based on experience of successful drilling and the average holding period. The fair value of non-producing properties is calculated using significant unobservable inputs (Level 3).

Proved properties were reviewed for impairment at June 30, 2011. No impairment provisions were recorded for the Company s proved crude oil and natural gas properties for the three or six month periods ended June 30, 2011. For those periods, future cash flows were determined to be in excess of cost basis, therefore no impairment was necessary. Certain non-producing properties were impaired at June 30, 2011, reflecting amortization of leasehold costs. The following table sets forth the pre-tax non-cash impairments of both proved and non-producing properties for the indicated periods. Proved and non-producing 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,**	
	2011	**2010**	**2011**	**2010**
		In thousands		
Proved property impairments	$	$ 729	$	$ 1,704
Non-producing property impairments	19,242	18,785	40,090	32,985
Total	$ 19,242	$ 19,514	$ 40,090	$ 34,689

Asset Retirement Obligations The fair value of asset retirement obligations (AROs) is estimated based on discounted cash flow projections using numerous estimates, assumptions and judgments regarding such factors as the existence of a legal obligation for an ARO, estimated probabilities, amounts and timing of settlements, the credit-adjusted risk-free rate to be used, and inflation rates. The fair values of ARO additions were $1.7 million for the six months ended June 30, 2011, which are reflected in the caption Asset retirement obligations, net of current portion in the condensed consolidated balance sheets. The fair values of AROs are calculated using significant unobservable inputs (Level 3).

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, 2011		**December 31, 2010**	
In thousands	**Carrying Amount**	**Fair Value**	**Carrying Amount**	**Fair Value**
Long-term debt				
Revolving credit facility	$	$	$ 30,000	$ 30,000
8 1/4% Senior Notes due 2019	297,786	327,250	297,696	331,500
7 3/8% Senior Notes due 2020	198,355	212,833	198,295	213,000
7 1/8% Senior Notes due 2021	400,000	421,367	400,000	419,333
Total	$ 896,141	$ 961,450	$ 925,991	$ 993,833

The fair value of the revolving credit facility approximates its carrying value based on the borrowing rates available to the Company for bank loans with similar terms and maturities. The fair values of the 8 1/4% Senior Notes due 2019, the 7 3/8% Senior Notes due 2020 and the 7 1/8% Senior Notes due 2021 are based on quoted market prices (Level 1).

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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, 2011	December 31, 2010
Revolving credit facility	$	$ 30,000
8 1/4% Senior Notes due 2019 (1)	297,786	297,696
7 3/8% Senior Notes due 2020 (2)	198,355	198,295
7 1/8% Senior Notes due 2021 (3)	400,000	400,000
Total long-term debt	$ 896,141	$ 925,991

(1) The carrying amount is net of discounts of $2.2 million and $2.3 million at June 30, 2011 and December 31, 2010, respectively.
(2) The carrying amount is net of discounts of $1.6 million and $1.7 million at June 30, 2011 and December 31, 2010, respectively.
(3) The notes were sold at par and are recorded at 100% of face value.

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Revolving credit facility

The Company had no debt outstanding at June 30, 2011 on its revolving credit facility which matures on July 1, 2015. At December 31, 2010, the Company had $30.0 million of outstanding borrowings on its revolving credit facility. The credit facility has aggregate commitments of $750.0 million and a borrowing base of $2.0 billion, subject to semi-annual redetermination. The most recent borrowing base redetermination was completed in June 2011, whereby the lenders approved an increase in the borrowing base from $1.5 billion to $2.0 billion. The terms of the facility provide that the commitment level can be increased up to the lesser of the borrowing base then in effect or $2.5 billion. Borrowings under the facility bear interest, payable quarterly, at a rate per annum equal to the London Interbank Offered Rate (LIBOR) for one, two, three or six months, as elected by the Company, plus a margin ranging from 175 to 275 basis points, depending on the percentage of the borrowing base utilized, or the lead bank s reference rate (prime) plus a margin ranging from 75 to 175 basis points. Borrowings are secured by the Company s interest in at least 85% (by value) of all of its proved reserves and associated crude oil and natural gas properties.

The Company had $747.6 million of unused commitments (after considering outstanding letters of credit) under its revolving credit facility at June 30, 2011 and incurs commitment fees of 0.50% per annum of the daily average amount of unused borrowing availability. The credit agreement contains certain restrictive covenants including a requirement that the Company maintain a current ratio of not less than 1.0 to 1.0 and a ratio of total funded debt to EBITDAX of no greater than 3.75 to 1.0. As defined by the credit agreement, the current ratio represents the ratio of current assets to current liabilities, inclusive of available borrowing capacity under the credit agreement and exclusive of current balances associated with derivative contracts and asset retirement obligations. EBITDAX represents earnings before interest expense, income taxes, depreciation, depletion, amortization and accretion, property impairments, exploration expenses, unrealized derivative gains and losses and non-cash equity compensation expense. EBITDAX is not a measure of net income or cash flows as determined by U.S. GAAP. A reconciliation of net income to EBITDAX is provided in *Part I, Item 2. Management s Discussion and Analysis of Financial Condition and Results of Operations Non-GAAP Financial Measures*. The total funded debt to EBITDAX ratio represents the sum of outstanding borrowings and letters of credit on the revolving credit facility plus the Company s senior note obligations, divided by total EBITDAX for the most recent four quarters. The Company was in compliance with all covenants at June 30, 2011.

Senior Notes

The 8 1/4% Senior Notes due 2019 (the 2019 Notes), the 7 3/8% Senior Notes due 2020 (the 2020 Notes), and the 7 1/8% Senior Notes due 2021 (the 2021 Notes) (collectively, the Notes) will mature on October 1, 2019, October 1, 2020, and April 1, 2021, respectively. Interest on the Notes is payable semi-annually on April 1 and October 1 of each year, with the payment of interest on the 2021 Notes having commenced on April 1, 2011. The Company has the option to redeem all or a portion of the 2019 Notes, 2020 Notes, and 2021 Notes at any time on or after October 1, 2014, October 1, 2015, and April 1, 2016, respectively, at the redemption prices specified in the Notes respective indentures (together, the Indentures) plus accrued and unpaid interest. The Company may also redeem the Notes, in whole or in part, at the make-whole redemption prices specified in the Indentures plus accrued and unpaid interest at any time prior to October 1, 2014, October 1, 2015, and April 1, 2016 for the 2019 Notes, 2020 Notes, and 2021 Notes, respectively. In addition, the Company may redeem up to 35% of the 2019 Notes, 2020 Notes, and 2021 Notes prior

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to October 1, 2012, October 1, 2013, and April 1, 2014, respectively, under certain circumstances with the net cash proceeds from certain equity offerings. The Notes are not subject to any mandatory redemption or sinking fund requirements.

The Indentures contain certain restrictions on the Company s ability to incur additional debt, pay dividends on common stock, make certain investments, create certain liens on assets, engage in certain transactions with affiliates, transfer or sell certain assets, consolidate or merge, or sell substantially all of the Company s assets. These covenants are subject to a number of important exceptions and qualifications. The Company was in compliance with these covenants at June 30, 2011. One of the Company s subsidiaries, Banner Pipeline Company, L.L.C., which currently has no independent assets or operations, fully and unconditionally guarantees the Notes. The Company s other subsidiary, whose assets and operations are minor, does not guarantee the Notes.

Note 7. Commitments and Contingencies

Drilling commitments As of June 30, 2011, the Company had drilling rig contracts with various terms extending through December 2012. 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. These drilling commitments are not recorded in the accompanying condensed consolidated balance sheets. Future commitments as of June 30, 2011 total approximately $96 million, of which $64 million is for contracts that expire in 2011 and $32 million is for contracts that expire in 2012.

Fracturing and well stimulation services arrangement In August 2010, the Company entered into an agreement with a third party whereby the third party will provide, on a take-or-pay basis, hydraulic fracturing services and related equipment to service certain of the Company s properties in North Dakota and Montana. The arrangement has a term of three years, beginning in October 2010, with two one-year extensions available to the Company at its discretion. Pursuant to the take-or-pay arrangement, the Company is to pay a fixed rate per day for a minimum number of days per calendar quarter over the three-year term regardless of whether or not the services are provided. The arrangement also stipulates the Company will bear the cost of certain products and materials used. Fixed commitments amount to $4.9 million per quarter, or $19.5 million annually, for total commitments of $58.5 million over the three-year term. Future commitments remaining as of June 30, 2011 amount to $43.9 million. The commitments under this arrangement are not recorded in the accompanying condensed consolidated balance sheets. Since the inception of this arrangement, the Company has been using the services more than the minimum number of days each quarter.

Delivery commitments In 2010, the Company signed a throughput and deficiency agreement with a third party crude oil pipeline company committing to ship 10,000 barrels of crude oil per day for five years at a tariff of $1.85 per barrel. The third party system commenced operations in June 2011. The Company will use this system to move some of its North region crude oil to market. Further, in 2011 the Company entered into crude oil rail delivery commitments with third parties committing to deliver a total of 16,500 barrels of crude oil per day to third party rail systems through the end of 2011. The Company will use the rail systems to move a portion of its North region crude oil to various markets.

Litigation In November 2010, an alleged class action was filed against the Company alleging the Company improperly deducted post-production costs from royalties paid to plaintiffs and other royalty interest owners from crude oil and natural gas wells located in Oklahoma. The plaintiffs seek recovery of compensatory damages, interest, punitive damages and attorney fees on behalf of the alleged class. The Company has responded to the petition, denied the allegations and raised a number of affirmative defenses. The action is in preliminary stages and discovery has recently commenced. The Company is not currently able to estimate what impact, if any, the action will have on its financial condition, results of operations or cash flows given the preliminary status of the matter and uncertainties with respect to, among other things, the nature of the claims and defenses, the potential size of the class, the scope and types of the properties and agreements involved, the production years involved, and the ultimate potential outcome of the matter.

The Company is involved in various other legal proceedings such as commercial disputes, claims from royalty and surface owners, property damage claims, personal injury claims and similar matters. While the outcome of these legal matters cannot be predicted with certainty, the Company does not expect them to have a material adverse effect on its financial condition, results of operations or cash flows. As of June 30, 2011 and December 31, 2010, the Company has recorded a liability in Other noncurrent liabilities of $4.4 million and $4.6 million, respectively, for various matters, none of which are believed to be individually significant.

Employee retirement plan The Company maintains a defined contribution retirement plan for its employees and makes discretionary contributions to the plan, up to the contribution limits established by the Internal Revenue Service, based on a percentage of each eligible employee s compensation. During 2010, contributions to the plan were 5% of eligible employees compensation, excluding bonuses. Effective January 1, 2011, the Company s contributions to the plan represent 3% of eligible employees compensation, including bonuses, in addition to matching 50% of eligible employees contributions up to 6%. Expenses associated with the plan amounted to $1.5 million and $0.8 million for the six months ended June 30, 2011, and 2010, respectively.

Employee health claims The Company generally self-insures employee health claims up to the first $125,000 per employee per year. The Company generally self-insures employee workers compensation claims up to the first $300,000 per employee per claim. Any amounts paid

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above these levels are reinsured through third-party providers. The Company accrues for claims that have been incurred but not yet reported based on a review of claims filed versus expected claims based on claims history. The accrued liability for health and workers compensation claims was $2.4 million and $1.9 million at June 30, 2011, and December 31, 2010, respectively.

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

Note 8. Stock-Based Compensation

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

	Three months ended June 30,		Six months ended June 30,	
	2011	2010	2011	2010
	In thousands			
Non-cash equity compensation	$3,855	$3,118	$7,497	$5,970

Stock Options

Effective October 1, 2000, the Company adopted the 2000 Plan and granted stock options to certain eligible employees. These grants consisted of either incentive stock options, nonqualified stock options or a combination of both. The granted stock options vest ratably over either a three or five-year period commencing on the first anniversary of the grant date and expire ten years from the date of grant. On November 10, 2005, the 2000 Plan was terminated. As of June 30, 2011, options covering 2,221,163 shares had been exercised and 540,868 had been canceled.

The Company s stock option activity under the 2000 Plan for the six months ended June 30, 2011 is presented below:

	Outstanding		Exercisable	
	Number of stock options	Weighted average exercise price	Number of stock options	Weighted average exercise price
Outstanding at December 31, 2010	104,970	$ 0.71	104,970	$ 0.71
Exercised	(12,470)	0.71	(12,470)	0.71
Outstanding at June 30, 2011	92,500	$ 0.71	92,500	$ 0.71

The intrinsic value of a stock option is the amount by which the value of the underlying stock exceeds the exercise price of the stock option at its exercise date. The total intrinsic value of stock options exercised during the six months ended June 30, 2011 was approximately $0.7 million. At June 30, 2011, all stock options were exercisable and had a weighted average remaining life of 9 months with an aggregate intrinsic value of $5.9 million.

Restricted Stock

On October 3, 2005, the Company adopted the 2005 Plan and reserved a maximum of 5,500,000 shares of common stock that may be issued pursuant to the 2005 Plan. As of June 30, 2011, the Company had 2,970,061 shares of restricted stock available to grant to directors, officers and key employees under the 2005 Plan. Restricted stock is awarded in the name of the recipient and except for the right of disposal, constitutes issued and outstanding shares of the Company s common stock for all corporate purposes during the period of restriction including the right to receive dividends, subject to forfeiture. Restricted stock grants generally vest over periods ranging from one to three years.

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A summary of changes in the non-vested shares of restricted stock for the six months ended June 30, 2011 is presented below:

	Number of non-vested shares	Weighted average grant-date fair value
Non-vested restricted shares at December 31, 2010	1,108,077	$ 35.72
Granted	59,740	67.88
Vested	(73,630)	34.10
Forfeited	(15,300)	37.81
Non-vested restricted shares at June 30, 2011	1,078,887	$ 37.58

The fair value of restricted stock represents the average of the high and low intraday market prices of the Company s common stock on the date of grant. Compensation expense for a restricted stock grant is a fixed amount determined at the grant date fair value and is recognized ratably over the vesting period as services are rendered by employees and directors. The expected life of restricted stock is based on the non-vested period that remains subsequent to the date of grant. There are no post-vesting restrictions related to the Company s restricted stock. The fair value of the restricted stock that vested during the six months ended June 30, 2011 at the vesting date was $4.8 million. As of June 30, 2011, there was $23.7 million of unrecognized compensation expense related to non-vested restricted stock. This expense is expected to be recognized ratably over a weighted average period of 1.3 years.

Note 9. Sale of Common Stock

On March 9, 2011, the Company and certain selling shareholders completed a public offering of an aggregate of 10,000,000 shares of the Company s common stock, including 9,170,000 shares issued and sold by the Company and 830,000 shares sold by the selling shareholders, at a price of $68.00 per share ($65.45 per share, net of the underwriting discount). The net proceeds to the Company from the offering amounted to approximately $599.7 million after deducting the underwriting discount and offering-related expenses. The Company did not receive any proceeds from the sale of shares by the selling shareholders. In connection with the offering, the Company granted the underwriters a 30-day overallotment option to purchase up to an additional 1,500,000 shares of common stock at the public offering price, less the underwriting discount, to cover overallotments, if any.

On March 25, 2011, the Company completed the sale of an additional 910,000 shares of its common stock at a price of $68.00 per share ($65.45 per share, net of the underwriting discount) in connection with the underwriters partial exercise of the overallotment option granted by the Company. The Company received additional net proceeds of approximately $59.5 million, after deducting the underwriting discount, from the partial exercise of the overallotment option. The selling shareholders did not participate in the partial exercise of the overallotment option.

The Company used $659.2 million of the total net proceeds from the offering to repay all amounts outstanding under its revolving credit facility and used the remaining net proceeds to fund a portion of its 2011 capital budget.

Note 10. Asset Disposition

In March 2011, the Company assigned certain non-strategic leaseholds located in the state of Michigan to a third party for cash proceeds of $22.0 million. In connection with the transaction, the Company recognized a pre-tax gain of $15.3 million which is included in the caption Gain on sale of assets in the unaudited condensed consolidated statements of income. The assignment involved undeveloped acreage with no proved reserves and no production or revenues.

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ITEM 2. Management s Discussion and Analysis of Financial Condition and Results of Operations

The following discussion and analysis should be read in conjunction with our historical consolidated financial statements and the notes included in our Annual Report on Form 10-K for the year ended December 31, 2010. Our operating results for the periods discussed may not be indicative of future performance. The following discussion and analysis includes forward-looking statements and should be read in conjunction with Risk Factors under Part II, Item 1A of this report, along with Cautionary Statement Regarding Forward-Looking Statements at the beginning of this report, for information about the risks and uncertainties that could cause our actual results to be materially different than our forward-looking statements.

Overview

We are engaged in crude oil and natural gas exploration, exploitation and production activities in the North, South, and East regions of the United States. The North region consists of properties north of Kansas and west of the Mississippi river and includes North Dakota Bakken, Montana Bakken, the Red River units and the Niobrara play in Colorado and Wyoming. The South region includes Kansas and all properties south of Kansas and west of the Mississippi river including the Anadarko Woodford and Arkoma Woodford plays in Oklahoma. The East region contains properties east of the Mississippi river including the Illinois Basin and the state of Michigan.

We focus our exploration activities in large new or developing plays that provide us the opportunity to acquire undeveloped acreage positions for future drilling operations. We have been successful in targeting large repeatable resource plays where horizontal drilling, advanced fracture stimulation and enhanced recovery technologies provide the means to economically develop and produce crude oil and natural gas reserves from unconventional formations. We derive the majority of our operating income and cash flows from the sale of crude oil and natural gas. We expect that growth in our revenues and operating income will primarily depend on product prices and our ability to increase our crude oil and natural gas production. In recent months and years, there has been significant volatility in crude oil and natural gas prices due to a variety of factors we cannot control or predict, including political and economic events, weather conditions, and competition from other energy sources. These factors impact supply and demand for crude oil and natural gas, which affects crude oil and natural gas prices. In addition, the prices we realize for our crude oil and natural gas production are affected by location differences in market prices.

For the first six months of 2011, our crude oil and natural gas production increased to 9,562 MBoe (52,830 Boe per day), up 2,289 MBoe, or 31%, from the first six months of 2010. The increase in 2011 production was primarily driven by an increase in production from our properties in the North Dakota Bakken field and the Anadarko Woodford play in Oklahoma due to the continued success of our drilling programs in those areas. Our Bakken production in North Dakota increased to 3,795 MBoe for the six months ended June 30, 2011, an 82% increase over the comparable 2010 period. Our production in the Anadarko Woodford play totaled 608 MBoe in the first half of 2011, 235% higher than the first half of 2010.

Our 2011 second quarter operations were adversely impacted by the heavy rainfall, power outages and unusual flooding that occurred in North Dakota during the quarter. Because of the adverse weather conditions, various counties in North Dakota imposed road restrictions on heavy trucks, causing us and other similarly situated operators to shut-in certain wells and delay certain drilling and completion projects, which hindered our production. Crude oil and natural gas production was 4,912 MBoe for the second quarter of 2011, a 6% increase over production of 4,650 MBoe for the first quarter of 2011 and a 29% increase over production of 3,815 MBoe for the second quarter of 2010. Our 2011 second quarter production was positively impacted by the continued success of our drilling programs in the Bakken Field and Anadarko Woodford play in Oklahoma, which offset the impact of the adverse weather conditions in North Dakota during the quarter.

Our crude oil and natural gas revenues for the first six months of 2011 increased 64% to $715.3 million due to a 26% increase in realized commodity prices along with increased production compared to the same period in 2010. Our realized price per Boe increased $15.71 to $75.63 for the six months ended June 30, 2011 compared to the six months ended June 30, 2010. At various times, we have stored crude oil due to pipeline line fill requirements, low commodity prices, or transportation constraints or we have sold crude oil from inventory. These actions result in differences between our produced and sold crude oil volumes. For the six months ended June 30, 2011, crude oil sales volumes were 104 MBbls less than crude oil production, and crude oil sales volumes were 13 MBbls more than crude oil production for the same period in 2010.

Our cash flows from operating activities for the six months ended June 30, 2011 were $429.0 million, an increase from $390.2 million provided by our operating activities during the comparable 2010 period. The increase in operating cash flows was primarily due to increased crude oil and natural gas revenues as a result of increased commodity prices and sales volumes, partially offset by an increase in realized losses on derivatives and higher production expenses, production taxes, and other operating expenses associated with the growth of our operations in the current year.

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In March 2011, our Board of Directors increased our 2011 capital expenditures budget from $1.36 billion to $1.75 billion to further accelerate our drilling program and increase our acreage positions in strategic plays in the United States. In early August 2011, our Board of Directors further increased our 2011 budget by $250 million to $2.0 billion. We plan to focus the additional investment primarily on increased drilling in the Bakken and Anadarko Woodford plays. Several changes contributed to the increased 2011 budget, including the success of our drilling program over the first six months of 2011, expected increases in the costs of well completion services attributed to an increase in the number of completion stages now being used on our North Dakota Bakken wells, our ability to secure more drilling rigs in the Anadarko Woodford play than we had initially budgeted, and an expected increase in the number of Bakken drilling sites to be pre-built in 2011 prior to the onset of winter weather. During the six months ended June 30, 2011, we have invested $868.5 million (including increased accruals for capital expenditures of $35.9 million and $6.2 million of seismic costs) in our capital program, concentrating mainly in the North Dakota Bakken field and the Anadarko Woodford play.

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

How We Evaluate Our Operations

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

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

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

	Three months ended June 30,		Six months ended June 30,	
	2011	**2010**	**2011**	**2010**
Average daily production:				
Crude oil (Bbl per day)	40,382	31,611	39,420	30,373
Natural gas (Mcf per day)	81,609	61,815	80,459	58,844
Crude oil equivalents (Boe per day)	53,984	41,913	52,830	40,180
Average sales prices: (1)				
Crude oil ($/Bbl)	$ 95.88	$ 68.44	$ 90.78	$ 69.87
Natural gas ($/Mcf)	5.47	4.33	5.29	4.84
Crude oil equivalents ($/Boe)	79.86	57.94	75.63	59.92
Production expenses ($/Boe) (1)	6.65	5.90	6.52	6.17
General and administrative expenses ($/Boe) (1) (2)	3.53	3.03	3.55	3.20
Net income (in thousands)	$ 239,194	$ 101,741	$ 101,993	$ 174,206
Diluted net income per share	1.33	0.60	0.58	1.03
EBITDAX (in thousands) (3)	$ 285,631	$ 217,462	$ 554,286	$ 393,045

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

(2) General and administrative expense ($/Boe) includes non-cash equity compensation expense of $0.79 per Boe and $0.82 per Boe for the three and six months ended June 30, 2011 and 2010.

(3) EBITDAX represents earnings before interest expense, income taxes, depreciation, depletion, amortization and accretion, property impairments, exploration expenses, unrealized derivative gains and losses and non-cash equity compensation expense. EBITDAX is not a measure of net income or cash flows as determined by U.S. GAAP. A reconciliation of net income to EBITDAX is provided subsequently under the heading *Non-GAAP Financial Measures*.

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Three months ended June 30, 2011 compared to the three months ended June 30, 2010

Results of Operations

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

	Three months ended June 30, 2011	Three months ended June 30, 2010
	In thousands, except sales price data	
Crude oil and natural gas sales	$ 388,784	$ 219,426
Gain on derivative instruments, net [1]	204,453	55,465
Total revenues	602,892	279,968
Operating costs and expenses [2]	198,584	103,645
Other expenses, net	17,763	11,825
Income before income taxes	386,545	164,498
Provision for income taxes	147,351	62,757
Net income	$ 239,194	$ 101,741
Production volumes:		
Crude oil (MBbl) [3]	3,675	2,877
Natural gas (MMcf)	7,426	5,625
Crude oil equivalents (MBoe)	4,912	3,815
Sales volumes:		
Crude oil (MBbl) [3]	3,631	2,849
Natural gas (MMcf)	7,426	5,625
Crude oil equivalents (MBoe)	4,869	3,788
Average sales prices: [4]		
Crude oil ($/Bbl)	$ 95.88	$ 68.44
Natural gas ($/Mcf)	$ 5.47	$ 4.33
Crude oil equivalents ($/Boe)	$ 79.86	$ 57.94

(1) Amounts include unrealized non-cash mark-to-market gains on derivative instruments of $231.3 million and $42.7 million for the three months ended June 30, 2011 and 2010, respectively.

(2) Net of gain on sale of assets of $0.3 million and $33.1 million for the three months ended June 30, 2011 and 2010, respectively. In June 2010, we sold certain non-strategic leaseholds located in Desoto Parish, Louisiana to a third party for cash proceeds of $35.4 million. In connection with the sale, we recognized a pre-tax gain of $31.7 million in the second quarter of 2010.

(3) At various times we have stored crude oil due to pipeline line fill requirements, low commodity prices, or transportation constraints or we have sold crude oil from inventory. These actions result in differences between our produced and sold crude oil volumes. Crude oil sales volumes were 44 MBbls less than crude oil production for the three months ended June 30, 2011 and 28 MBbls less than crude oil production for the three months ended June 30, 2010.

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

Production

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

	Three months ended June 30, 2011 Volume	2011 Percent	2010 Volume	2010 Percent	Volume increase	Percent increase
Crude oil (MBbl)	3,675	75%	2,877	75%	798	28%

Natural Gas (MMcf)	7,426	25%	5,625	25%	1,801	32%
Total (MBoe)	4,912	100%	3,815	100%	1,097	29%

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	Three months ended June 30, 2011		2010		Volume increase	Percent increase
	MBoe	Percent	MBoe	Percent	(decrease)	(decrease)
North Region	3,870	79%	3,033	80%	837	28%
South Region	945	19%	675	17%	270	40%
East Region	97	2%	107	3%	(10)	(9)%
Total	4,912	100%	3,815			