CONTINENTAL RESOURCES INC
Form 10-Q
November 03, 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 September 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	**(I.R.S. Employer**
incorporation or organization)	**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

180,483,387 shares of our $0.01 par value common stock were outstanding on October 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.

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

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

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

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

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Cautionary Statement Regarding Forward-Looking Statements

Certain statements and information in this report may constitute forward-looking statements within the meaning of the Private Securities Litigation Reform Act of 1995. All statements other than statements of historical fact included in this report are forward-looking statements. When used in this report, the words could, may, believe, anticipate, intend, estimate, expect, project and similar expressions are 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;

- transportation of crude oil and natural gas to market;
- 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

	September 30, 2011 (Unaudited)	December 31, 2010
	In thousands, except par values and share data	
Assets		
Current assets:		
Cash and cash equivalents	$ 42,275	$ 7,916
Receivables:		
Crude oil and natural gas sales	290,826	208,211
Affiliated parties	27,329	20,156
Joint interest and other, net	342,310	254,471
Derivative assets	114,323	21,365
Inventories	61,690	38,362
Deferred and prepaid taxes	1,997	22,672
Prepaid expenses and other	27,074	9,173
Total current assets	907,824	582,326
Net property and equipment, based on successful efforts method of accounting	4,046,235	2,981,991
Debt issuance costs, net	24,716	27,468
Noncurrent derivative assets	120,802	
Total assets	$ 5,099,577	$ 3,591,785
Liabilities and shareholders equity		
Current liabilities:		
Accounts payable trade	$ 526,252	$ 390,892
Revenues and royalties payable	188,944	133,051
Payables to affiliated parties	8,109	4,438
Accrued liabilities and other	154,782	94,829
Derivative liabilities		76,771
Current portion of asset retirement obligations	2,640	2,241
Total current liabilities	880,727	702,222
Long-term debt	896,220	925,991
Other noncurrent liabilities:		
Deferred income tax liabilities	843,332	582,841
Asset retirement obligations, net of current portion	56,930	54,079
Noncurrent derivative liabilities		112,940
Other noncurrent liabilities	3,750	5,557
Total other noncurrent liabilities	904,012	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; 180,533,960 shares issued and outstanding at September 30, 2011; 170,408,652 shares issued and outstanding at December 31, 2010	1,805	1,704
Additional paid-in capital	1,109,126	439,900
Retained earnings	1,307,687	766,551
Total shareholders equity	2,418,618	1,208,155
Total liabilities and shareholders equity	$ 5,099,577	$ 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 September 30,		Nine months ended September 30,	
	2011	2010	2011	2010
	In thousands, except per share data			
Revenues:				
Crude oil and natural gas sales	$ 408,037	$ 232,662	$ 1,103,165	$ 651,925
Crude oil and natural gas sales to affiliates	15,822	6,164	35,945	23,451
Gain (loss) on derivative instruments, net	537,340	(24,183)	372,490	57,626
Crude oil and natural gas service operations	7,790	4,807	24,071	14,684
Total revenues	968,989	219,450	1,535,671	747,686
Operating costs and expenses:				
Production expenses	35,666	23,626	95,508	64,044
Production expenses to affiliates	793	1,231	2,582	5,762
Production taxes and other expenses	39,262	19,517	100,315	53,755
Exploration expenses	9,814	3,530	21,660	7,585
Crude oil and natural gas service operations	6,198	4,935	19,713	12,982
Depreciation, depletion, amortization and accretion	105,085	62,918	264,236	174,327
Property impairments	26,225	14,698	66,315	49,387
General and administrative expenses	18,140	12,148	51,696	35,491
(Gain) loss on sale of assets	188	491	(15,387)	(32,855)
Total operating costs and expenses	241,371	143,094	606,638	370,478
Income from operations	727,618	76,356	929,033	377,208
Other income (expense):				
Interest expense	(18,981)	(12,612)	(56,737)	(32,875)
Other	994	237	2,525	1,021
	(17,987)	(12,375)	(54,212)	(31,854)
Income before income taxes	709,631	63,981	874,821	345,354
Provision for income taxes	270,488	24,904	333,685	132,071
Net income	$ 439,143	$ 39,077	$ 541,136	$ 213,283
Basic net income per share	$ 2.45	$ 0.23	$ 3.06	$ 1.26
Diluted net income per share	$ 2.44	$ 0.23	$ 3.05	$ 1.26

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)				541,136	541,136
Public offering of common stock (unaudited)	10,080,000	101	659,131		659,232
Stock-based compensation (unaudited)			11,742		11,742
Stock options:					
Exercised (unaudited)	12,470		9		9
Repurchased and canceled (unaudited)	(2,495)		(150)		(150)
Restricted stock:					
Issued (unaudited)	79,060				
Repurchased and canceled (unaudited)	(23,293)		(1,506)		(1,506)
Forfeited (unaudited)	(20,434)				
Balance, September 30, 2011	180,533,960	$ 1,805	$ 1,109,126	$ 1,307,687	$ 2,418,618

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

	Nine months ended September 30, 2011	2010
Cash flows from operating activities:	*In thousands*	
Net income	$ 541,136	$ 213,283
Adjustments to reconcile net income to net cash provided by operating activities:		
Depreciation, depletion, amortization and accretion	266,281	173,321
Property impairments	66,315	49,387
Change in fair value of derivatives	(403,471)	(28,162)
Stock-based compensation	11,742	8,596
Provision for deferred income taxes	324,354	116,165
Dry hole costs	3,758	1,943
Gain on sale of assets	(15,387)	(32,855)
Other, net	2,800	3,631
Changes in assets and liabilities:		
Accounts receivable	(177,627)	(192,970)
Inventories	(23,543)	(4,345)
Prepaid expenses and other	(18,937)	2,105
Accounts payable trade	21,206	99,869
Revenues and royalties payable	55,893	28,716
Accrued liabilities and other	17,012	54,008
Other noncurrent liabilities	(1,718)	2,648
Net cash provided by operating activities	669,814	495,340
Cash flows from investing activities:		
Exploration and development	(1,245,688)	(719,843)
Purchase of crude oil and natural gas properties	(2,771)	(7,319)
Purchase of other property and equipment	(37,449)	(20,453)
Proceeds from sale of assets	22,769	38,662
Net cash used in investing activities	(1,263,139)	(708,953)
Cash flows from financing activities:		
Revolving credit facility borrowings	135,000	289,000
Repayment of revolving credit facility	(165,000)	(515,000)
Proceeds from issuance of Senior Notes		587,210
Proceeds from issuance of common stock	659,736	
Debt issuance costs	(37)	(8,796)
Equity issuance costs	(368)	(136)
Repurchase of equity grants	(1,656)	(3,658)
Dividends to shareholders		(3)
Exercise of stock options	9	251
Net cash provided by financing activities	627,684	348,868
Net change in cash and cash equivalents	34,359	135,255
Cash and cash equivalents at beginning of period	7,916	14,222
Cash and cash equivalents at end of period	$ 42,275	$ 149,477

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 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 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, 2010 (2010 Form 10-K), which includes a summary of the Company s significant accounting policies and other disclosures.

The financial statements as of September 30, 2011 and for the three and nine month periods ended September 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	**September 30, 2011**	**December 31, 2010**
Tubular goods and equipment	$ 18,973	$ 16,306
Crude oil	42,717	22,056
Total	$ 61,690	$ 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	**September 30, 2011**	**December 31, 2010**
Crude oil line fill requirements	374,000	257,000
Temporarily stored crude oil	339,000	148,000
Total	713,000	405,000

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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 nine months ended September 30, 2011 and 2010:

	Three months ended September 30,		Nine months ended September 30,	
	2011	2010	2011	2010
	In thousands, except per share data			
Income (numerator):				
Net income - basic and diluted	$ 439,143	$ 39,077	$ 541,136	$ 213,283
Weighted average shares (denominator):				
Weighted average shares - basic	179,458	168,925	176,899	168,889
Nonvested restricted stock	696	740	705	719
Employee stock options	91	284	97	296
Weighted average shares - diluted	180,245	169,949	177,701	169,904
Net income per share:				
Basic	$ 2.45	$ 0.23	$ 3.06	$ 1.26
Diluted	$ 2.44	$ 0.23	$ 3.05	$ 1.26

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.

	Nine months ended September 30,	
	2011	2010
	In thousands	
Supplemental cash flow information:		
Cash paid for interest	$ 69,658	$ 17,218
Cash paid for income taxes	$ 10,485	$ 10,876
Cash received for income tax refunds	$ (116)	$ (1,288)
Non-cash investing activities:		
Asset retirement obligations, net	$ 1,691	$ 1,325

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 upward price movements.

During the nine months ended September 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 in the future. None of the new contracts have been designated for hedge accounting.

Continental Resources, Inc. and Subsidiaries

Notes to Unaudited Condensed Consolidated Financial Statements

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*.

At September 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**
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

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

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Continental Resources, Inc. and Subsidiaries

Notes to Unaudited Condensed Consolidated Financial Statements

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 September 30,		Nine months ended September 30,	
	2011	2010	2011	2010
	In thousands			
Realized gain (loss) on derivatives:				
Crude oil fixed price swaps	$ (1,918)	$ 5,845	$ (9,894)	$ 13,275
Crude oil collars	(5,364)	825	(45,005)	1,884
Natural gas fixed price swaps	8,395	6,373	23,918	16,628
Natural gas basis swaps		(674)		(2,323)
Total realized gain (loss) on derivatives	$ 1,113	$ 12,369	$ (30,981)	$ 29,464
Unrealized gain (loss) on derivatives				
Crude oil fixed price swaps	$ 277,803	$ (17,538)	$ 199,939	$ (6,727)
Crude oil collars	257,816	(28,640)	210,300	6,445
Natural gas fixed price swaps	608	9,258	(6,768)	26,552
Natural gas basis swaps		368		1,892
Total unrealized gain (loss) on derivatives	$ 536,227	$ (36,552)	$ 403,471	$ 28,162
Gain (loss) on derivative instruments, net	$ 537,340	$ (24,183)	$ 372,490	$ 57,626

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

	September 30, 2011			December 31, 2010		
	Assets	(Liabilities)	Net	Assets	(Liabilities)	Net
In thousands	Fair Value	Fair Value	Fair Value	Fair Value	Fair Value	Fair Value
Commodity swaps and collars	$ 235,125	$	$ 235,125	$ 21,365	$ (189,711)	$ (168,346)

Note 5. Fair Value Measurements

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

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

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

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

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

Assets and Liabilities Measured at Fair Value on a Recurring Basis

Certain assets and liabilities are reported at fair value on a recurring basis, including the Company s derivative instruments. In determining the fair values of fixed price swaps and basis swaps, a discounted cash flow method is used due to the unavailability of

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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, observable inputs relating to basis differentials and a risk-adjusted discount rate. The fair values of fixed price swaps and basis 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 September 30, 2011 and December 31, 2010. Transfers out of Level 3 during the three months ended September 30, 2011 were attributable to the Company s ability to corroborate the volatility factors used to value its collar contracts with observable changes in forward commodity prices, which resulted in the Company transferring its collar contracts from Level 3 to Level 2 during the third quarter. The unrealized mark-to-market gain recognized in earnings on the collar contracts for the three months ended September 30, 2011 amounted to $257.8 million.

	Fair value measurements at September 30, 2011 using:			
Description	**Level 1**	**Level 2**	**Level 3**	**Total**
		In thousands		
Derivative assets (liabilities):				
Fixed price swaps	$	$ 128,242	$	$ 128,242
Collars		106,883		106,883
Total	$	$ 235,125	$	$ 235,125

	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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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
Total realized or unrealized gains (losses), net:		
Included in earnings		(28,640)
Included in other comprehensive income		
Purchases		
Sales		
Issuances		
Settlements		
Transfers into Level 3		
Transfers out of Level 3	150,933	
Balance at September 30	$	$ 3,170
Unrealized gains (losses) relating to derivatives still held at September 30	$ (49,102)	$ 6,631

Gains and losses included in earnings for the three and nine month periods ended September 30, 2011 and 2010 attributable to the change in unrealized gains and losses relating to derivatives held at September 30, 2011 and 2010 are reported in the unaudited condensed consolidated statements of income under the caption Gain (loss) on derivative instruments, net.

Assets and Liabilities Measured at Fair Value on a Nonrecurring Basis

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

Asset Impairments Proved crude oil and natural gas properties are reviewed for impairment 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 assessed. 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 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. The fair value of non-producing properties is calculated using significant unobservable inputs (Level 3).

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Proved properties were reviewed for impairment at September 30, 2011. 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 $7.6 million for the nine months ended September 30, 2011, all of which was recognized in the third quarter. Further, certain non-producing properties were impaired at September 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 September 30,		Nine months ended September 30,	
	2011	2010	2011	2010
	In thousands			
Proved property impairments	$ 7,613	$	$ 7,613	$ 1,674
Non-producing property impairments	18,612	14,698	58,702	47,713
Total	$ 26,225	$ 14,698	$ 66,315	$ 49,387

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 factors such 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 $0.7 million and $2.4 million for the three and nine months ended September 30, 2011, respectively, which are reflected in the caption Asset retirement obligations, net of current portion in the condensed consolidated balance sheets. The fair values of AROs are calculated using significant unobservable inputs (Level 3).

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.

	September 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	297,833	321,750	297,696	331,500
7 3/8% Senior Notes due 2020	198,387	208,000	198,295	213,000
7 1/8% Senior Notes due 2021	400,000	408,333	400,000	419,333
Total	$ 896,220	$ 938,083	$ 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).

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	September 30, 2011	December 31, 2010
Revolving credit facility	$	$ 30,000
8 1/4% Senior Notes due 2019 (1)	297,833	297,696
7 3/8% Senior Notes due 2020 (2)	198,387	198,295
7 1/8% Senior Notes due 2021 (3)	400,000	400,000
Total long-term debt	$ 896,220	$ 925,991

(1) The carrying amount is net of discounts of $2.2 million and $2.3 million at September 30, 2011 and December 31, 2010, respectively.
(2) The carrying amount is net of discounts of $1.6 million and $1.7 million at September 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 September 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 had aggregate commitments of $750.0 million and a borrowing base of $2.0 billion at September 30, 2011, subject to semi-annual redetermination. A borrowing base redetermination was completed in October 2011, whereby the lenders approved an increase in the borrowing base from $2.0 billion to $2.25 billion. 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 $747.0 million of unused commitments (after considering outstanding letters of credit) under its revolving credit facility at September 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 September 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 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 September 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 September 30, 2011, 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. These drilling commitments are not recorded in the accompanying condensed consolidated balance sheets.

Future commitments as of September 30, 2011 total approximately $180 million, of which $49 million is expected to be incurred in 2011, $88 million in 2012, $27 million in 2013, and $16 million in 2014.

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Fracturing and well stimulation services agreement The Company has an agreement with a third party whereby the third party will provide, on a take-or-pay basis, hydraulic fracturing services and related equipment to service certain of the Company s properties in North Dakota and Montana. The agreement has a term of three years, beginning October 2010, with two one-year extensions available to the Company at its discretion. Pursuant to the take-or-pay provisions, the Company is to pay a fixed rate per day for a minimum number of days per calendar quarter over the three-year term regardless of whether or not the services are provided. The agreement also stipulates the Company will bear the cost of certain products and materials used. Future commitments remaining as of September 30, 2011 amount to approximately $45 million, of which $6 million is expected to be incurred in 2011, $22 million in 2012, and $17 million in 2013. The commitments under this agreement are not recorded in the accompanying condensed consolidated balance sheets. Since the inception of this agreement, the Company has been using the services more than the minimum number of days each quarter.

Firm transportation commitments In 2010, the Company entered into a five-year firm transportation commitment to guarantee capacity totaling 10,000 barrels of crude oil per day on a major pipeline in order to reduce the impact of possible production curtailments that may arise due to limited transportation capacity. The transportation commitment is for crude oil production in the Bakken field where the Company allocates a significant portion of its capital expenditures. The commitment requires the Company to pay transportation reservation charges of $1.85 per barrel, or $6.8 million annually, regardless of the amount of pipeline capacity used. Payments under the agreement began in the second quarter of 2011 in conjunction with the commencement of the pipeline system s operations. To date, production delivered to the pipeline system has exceeded the daily volumes provided in the contract. The commitments under this agreement are not recorded in the accompanying condensed consolidated balance sheets. The Company is not committed under this contract, or any other existing contract, to deliver fixed and determinable quantities of crude oil or natural gas in the future.

Litigation In November 2010, an alleged class action was filed against the Company alleging the Company improperly deducted post-production costs from royalties paid to plaintiffs and other royalty interest owners from crude oil and natural gas wells located in Oklahoma. The plaintiffs seek recovery of compensatory damages, interest, punitive damages and attorney fees on behalf of the alleged class. The Company has responded to the petition, denied the allegations and raised a number of affirmative defenses. The action is in preliminary stages and discovery has 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 September 30, 2011 and December 31, 2010, the Company has recorded a liability in the condensed consolidated balance sheets under the caption Other noncurrent liabilities of $2.7 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 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 $2.2 million and $1.0 million for the nine months ended September 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. Amounts paid above this level are reinsured through third-party providers. The Company generally self-insures employee workers compensation claims up to the first $300,000 per employee per claim. Amounts paid above this level are reinsured through third-party providers up to $1 million in excess of the self-insured retention. The Company accrues for claims that have been incurred but not yet reported based on a review of claims filed versus expected claims based on claims history. The accrued liability for health and workers compensation claims was $2.7 million and $1.9 million at September 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.

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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 September 30,		Nine months ended September 30,	
	2011	2010	2011	2010
	In thousands			
Non-cash equity compensation	$ 4,245	$ 2,626	$ 11,742	$ 8,596

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 September 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 nine months ended September 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 September 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 nine months ended September 30, 2011 was $0.7 million. At September 30, 2011, all stock options were exercisable and had a weighted average remaining life of 6 months with an aggregate intrinsic value of $4.4 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 September 30, 2011, the Company had 2,963,015 shares of restricted stock available to grant to directors, officers and key employees under the 2005 Plan. Restricted stock is awarded in the name of the recipient and except for the right of disposal, constitutes issued and outstanding shares of the Company s common stock for all corporate purposes during the period of restriction including the right to receive dividends, subject to forfeiture. Restricted stock grants generally vest over periods ranging from one to three years.

A summary of changes in the non-vested shares of restricted stock for the nine months ended September 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	79,060	67.07
Vested	(95,713)	37.89
Forfeited	(20,434)	38.99
Non-vested restricted shares at September 30, 2011	1,070,990	$ 37.78

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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 nine months ended September 30, 2011 at the vesting date was $6.2 million. As of September 30, 2011, there was $20.6 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 1.1 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 the total net proceeds from the offering of $659.2 million to repay all amounts outstanding under its revolving credit facility and 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) loss 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 the risk factors 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, along with Cautionary Statement Regarding Forward-Looking Statements at the beginning of this report, for information about the risks and uncertainties that could cause our actual results to be materially different than our forward-looking statements.

Overview

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

We focus our exploration activities in large new or developing plays that provide us the opportunity to acquire undeveloped acreage positions for future drilling operations. We have been successful in targeting large repeatable resource plays where horizontal drilling, advanced fracture stimulation and enhanced recovery technologies provide the means to economically develop and produce crude oil and natural gas reserves from unconventional formations. We derive the majority of our operating income and cash flows from the sale of crude oil and natural gas. We expect that growth in our revenues and operating income will primarily depend on 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 affect crude oil and natural gas prices. In addition, the prices we realize for our crude oil and natural gas production are affected by price differences in the markets where we deliver our production.

For the first nine months of 2011, our crude oil and natural gas production increased to 15,661 MBoe (57,365 Boe per day), up 4,269 MBoe, or 37%, from the first nine months of 2010. Crude oil and natural gas production was 6,099 MBoe for the third quarter of 2011, a 24% increase over production of 4,912 MBoe for the second quarter of 2011 and a 48% increase over production of 4,119 MBoe for the third quarter of 2010. The increase in 2011 production was primarily driven by an increase in production from our properties in the North Dakota Bakken field and the Anadarko Woodford play in Oklahoma due to the continued success of our drilling programs in those areas. Our Bakken production in North Dakota increased to 6,461 MBoe for the nine months ended September 30, 2011, an 86% increase over the comparable 2010 period. Our production in the Anadarko Woodford play totaled 1,268 MBoe in the first nine months of 2011, 598% higher than the first nine months of 2010.

Our crude oil and natural gas revenues for the first nine months of 2011 increased 69% to $1,139.1 million due to a 25% increase in realized commodity prices along with increased production compared to the same period in 2010. For the 2011 third quarter, crude oil and natural gas revenues were $423.9 million, a 77% increase from the 2010 third quarter due to a 22% increase in realized commodity prices along with increased production. Our realized price per Boe increased $14.43 to $73.25 for the nine months ended September 30, 2011 compared to the nine months ended September 30, 2010. For the 2011 third quarter, our realized price per Boe was $69.57, an increase of $12.65 compared to the 2010 third quarter.

The differential between NYMEX calendar month average crude oil prices and our realized crude oil price per barrel for the nine months ended September 30, 2011 was $7.00 compared to $8.68 for the nine months ended September 30, 2010 and $9.02 for the year ended December 31, 2010. For the third quarter of 2011, the crude oil price differential was $5.62, an improvement over differentials of $6.59 for the second quarter of 2011 and $8.93 for the third quarter of 2010. A significant portion of our operated crude oil production in the North region is being sold in markets other than Cushing, Oklahoma and is priced, apart from transportation costs, at a premium to West Texas Intermediate benchmark pricing, which has resulted in improved differentials.

Our cash flows from operating activities for the nine months ended September 30, 2011 were $669.8 million, an increase from $495.3 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.

Our capital expenditures budget for 2011 is $2.0 billion. During the nine months ended September 30, 2011, we have invested $1,418.1 million in our capital program (including increased accruals for capital expenditures of $117.8 million and $14.4 million of seismic costs), concentrating mainly in the North Dakota Bakken field and the Anadarko Woodford play. In November 2011, our Board of Directors approved a 2012 capital expenditures budget of $1.75 billion, a $250 million reduction from our 2011 capital budget. While our 2012 capital plan will continue to focus primarily on increased development in the North Dakota Bakken field and Anadarko Woodford play, we plan to moderate our Bakken growth in 2012 and conserve capital while infrastructure is developed to accommodate industry growth in North Dakota.

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Due to the volatility of crude oil and natural gas prices and our desire to develop our substantial inventory of undeveloped reserves as part of our capital program, we have hedged a substantial portion of our forecasted production from our estimated proved reserves through 2013. We expect our cash flows from operations, our remaining cash balance, and the availability of our 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 September 30, 2011	Three months ended September 30, 2010	Nine months ended September 30, 2011	Nine months ended September 30, 2010
Average daily production:				
Crude oil (Bbl per day)	47,552	33,432	42,160	31,404
Natural gas (Mcf per day)	112,423	68,057	91,231	61,948
Crude oil equivalents (Boe per day)	66,289	44,775	57,365	41,728
Average sales prices: (1)				
Crude oil ($/Bbl)	$ 84.02	$ 67.26	$ 88.19	$ 68.92
Natural gas ($/Mcf)	5.50	4.28	5.37	4.63
Crude oil equivalents ($/Boe)	69.57	56.92	73.25	58.82
Production expenses ($/Boe) (1)	5.98	5.92	6.31	6.08
General and administrative expenses ($/Boe) (1) (2)	2.98	2.90	3.32	3.09
Net income (in thousands)	439,143	39,077	541,136	213,283
Diluted net income per share	2.44	0.23	3.05	1.26
EBITDAX (in thousands) (3)	337,754	196,917	892,040	589,962

(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 $0.70 per Boe and $0.63 per Boe for the three months ended September 30, 2011 and 2010, respectively, and $0.76 per Boe and $0.75 per Boe for the nine months ended September 30, 2011 and 2010, respectively.

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

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

Results of Operations

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

	Three months ended September 30, 2011	2010
	In thousands, except sales price data	
Crude oil and natural gas sales	$ 423,859	$ 238,826
Gain (loss) on derivative instruments, net [1]	537,340	(24,183)
Total revenues	968,989	219,450
Operating costs and expenses	(241,371)	(143,094)
Other expenses, net	(17,987)	(12,375)
Income before income taxes	709,631	63,981
Provision for income taxes	(270,488)	(24,904)
Net income	$ 439,143	$ 39,077
Production volumes:		
Crude oil (MBbl) [2]	4,375	3,075
Natural gas (MMcf)	10,343	6,261
Crude oil equivalents (MBoe)	6,099	4,119
Sales volumes:		
Crude oil (MBbl) [2]	4,368	3,153
Natural gas (MMcf)	10,343	6,261
Crude oil equivalents (MBoe)	6,092	4,195
Average sales prices: [3]		
Crude oil ($/Bbl)	$ 84.02	$ 67.26
Natural gas ($/Mcf)	5.50	4.28
Crude oil equivalents ($/Boe)	69.57	56.92

(1) Amounts include an unrealized non-cash mark-to-market gain on derivative instruments of $536.2 million for the three months ended September 30, 2011 and an unrealized non-cash mark-to-market loss on derivative instruments of $36.6 million for the three months ended September 30, 2010.

(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 7 MBbls less than crude oil production for the three months ended September 30, 2011 and 78 MBbls more than crude oil production for the three months ended September 30, 2010.

(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 September 30, 2011		2010			
	Volume	Percent	Volume	Percent	Volume increase	Percent increase
Crude oil (MBbl)	4,375	72%	3,075	75%	1,300	42%
Natural Gas (MMcf)	10,343	28%	6,261	25%	4,082	65%

Total (MBoe)	6,099	100%	4,119	100%	1,980	48%

	Three months ended September 30,				Volume	Percent
	2011		2010		increase	increase
	MBoe	Percent	MBoe	Percent	(decrease)	(decrease)
North Region	4,647	76%	3,230	78%	1,417	44%
South Region	1,348	22%	776	19%	572	74%
East Region	104	2%	113	3%	(9)	(8%)
Total	6,099	100%	4,119	100%	1,980	48%

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Crude oil production volumes increased 42% during the three months ended September 30, 2011 compared to the three months ended September 30, 2010. Production increases in the North Dakota Bakken field and the Anadarko Woodford play contributed incremental production volumes in 2011 of 1,165 MBbls, a 95% increase over production in these areas for the third quarter of 2010. Production growth in these areas is primarily due to increased drilling activity and higher well completions resulting from our accelerated drilling program for 2011. Additionally, production in the Cedar Hills field increased 61 MBbls, or 6%, in 2011 due to new wells being completed and enhanced recovery techniques being successfully applied in this legacy field.

Natural gas production volumes increased 4,082 MMcf, or 65%, during the three months ended September 30, 2011 compared to the same period in 2010. Natural gas production in the North Dakota Bakken field increased 1,037 MMcf, or 100%, for the three months ended September 30, 2011 compared to the same period in 2010 due to new wells being completed and gas from existing wells being connected to natural gas processing plants in North Dakota. We expect natural gas production growth in North Dakota Bakken to be further enhanced by the increased capacity of natural gas processing plants in the play, which will enable us to deliver more natural gas to market. Natural gas production in the Anadarko Woodford play increased 2,854 MMcf, or 427%, due to additional wells being completed and producing in the three months ended September 30, 2011 compared to the same period in 2010.

Revenues

Our total revenues are comprised of sales of crude oil and natural gas, revenues associated with crude oil and natural gas service operations, and realized and unrealized changes in the fair value of our derivative instruments. Throughout 2010 and 2011 we entered into a series 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 accelerated drilling program over the next three years. Changes in commodity futures price strips during the third quarter of 2011 had a positive impact on the fair value of our derivatives, which resulted in positive revenue adjustments of $537.3 million for the three months ended September 30, 2011. The $537.3 million positive adjustment includes $536.2 million of unrealized non-cash mark-to-market gains on open derivative instruments and $1.1 million of realized gains on derivatives during the quarter. The unrealized mark-to-market gain relates to derivative instruments with various terms that are scheduled to be realized over the period from October 2011 through December 2013. Over this period, actual realized derivative settlements may differ significantly from the unrealized mark-to-market valuation at September 30, 2011. We expect our revenues will continue to be significantly impacted, either positively or negatively, by changes in the fair value of our derivative instruments as a result of volatility in crude oil and natural gas prices.

Crude Oil and Natural Gas Sales. Crude oil and natural gas sales for the three months ended September 30, 2011 were $423.9 million, a 77% increase from sales of $238.8 million for the same period in 2010. Our sales volumes increased 1,897 MBoe, or 45%, over the same period in 2010 due to the continuing success of our drilling programs in the North Dakota Bakken field and Anadarko Woodford play. Our realized price per Boe increased $12.65 to $69.57 for the three months ended September 30, 2011 from $56.92 for the three months ended September 30, 2010. The differential between NYMEX calendar month average crude oil prices and our realized crude oil price per barrel for the three months ended September 30, 2011 was $5.62 compared to $8.93 for the three months ended September 30, 2010 and $9.02 for the year ended December 31, 2010. A significant portion of our operated crude oil production in the North region is being sold in markets other than Cushing, Oklahoma and is priced, apart from transportation costs, at a premium to West Texas Intermediate benchmark pricing, which has resulted in improved differentials.

Derivatives. We are required to recognize all derivative instruments on the balance sheet as either assets or liabilities measured at fair value. We have not designated our derivative instruments as hedges for accounting purposes. As a result, we mark our derivative instruments to fair value and recognize the realized and unrealized changes in fair value of derivative instruments in the unaudited condensed consolidated statements of income under the caption Gain (loss) on derivative instruments, net , which is a component of total revenues.

During the three months ended September 30, 2011, we realized losses on crude oil derivatives of $7.3 million and realized gains on natural gas derivatives of $8.4 million. During the three months ended September 30, 2011, we reported unrealized non-cash mark-to-market gains on crude oil derivatives of $535.6 million and natural gas derivatives of $0.6 million. During the three months ended September 30, 2010, we realized gains on crude oil derivatives of $6.7 million and natural gas derivatives of $5.7 million. During the three months ended September 30, 2010, we reported an unrealized non-cash mark-to-market loss on crude oil derivatives of $46.2 million and an unrealized non-cash mark-to-market gain on natural gas derivatives of $9.6 million.

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Crude Oil and Natural Gas Service Operations. Our crude oil and natural gas service operations consist primarily of the treatment and sale of lower quality crude oil, or reclaimed crude oil. The table below shows the volumes and prices for the sale of reclaimed crude oil for the periods presented.

Reclaimed crude oil sales	Three months ended September 30, 2011	2010	Increase
Average sales price ($/Bbl)	$ 87.62	$ 72.17	$ 15.45
Sales volumes (barrels)	66,000	52,000	14,000

Prices for reclaimed crude oil sold from our central treating units were $15.45 per barrel higher for the three months ended September 30, 2011 than the comparable 2010 period, which contributed to an increase in reclaimed crude oil revenue of $2.4 million to $5.8 million and contributed to an overall increase in crude oil and natural gas service operations revenue of $3.0 million for the three months ended September 30, 2011. Also contributing to the increase in crude oil and natural gas service operations revenue was a $0.3 million increase in saltwater disposal income resulting from increased activity. Associated crude oil and natural gas service operations expenses increased $1.3 million to $6.2 million during the three months ended September 30, 2011 from $4.9 million during the three months ended September 30, 2010 due mainly to an increase in the costs of purchasing and treating reclaimed crude oil for resale and in providing saltwater disposal services.

Operating Costs and Expenses

Production Expenses and Production Taxes and Other Expenses. Production expenses increased 47% to $36.5 million during the three months ended September 30, 2011 from $24.9 million during the three months ended September 30, 2010. This increase is primarily the result of higher production volumes from an increase in the number of producing wells. Production expense per Boe was $5.98 for the three months ended September 30, 2011 compared to $5.92 per Boe for the three months ended September 30, 2010.

Production taxes and other expenses increased $19.7 million, or 101%, to $39.3 million during the three months ended September 30, 2011 compared to the three months ended September 30, 2010 as a result of higher crude oil and natural gas revenues resulting from increased commodity prices and sales volumes along with the expiration of various tax incentives. Production taxes and other expenses in the unaudited condensed consolidated statements of income include other charges for marketing, gathering, dehydration and compression fees primarily related to natural gas sales in the Oklahoma Woodford and North Dakota Bakken areas of $5.2 million and $1.1 million for the three months ended September 30, 2011 and 2010, respectively. The increase in other charges is primarily due to the significant increase in natural gas sales volumes in the current period. Production taxes, excluding other charges, as a percentage of crude oil and natural gas revenues were 8.0% for the three months ended September 30, 2011 compared to 7.7% for the three months ended September 30, 2010. The increase is due to the expiration of various tax incentives coupled with higher taxable revenues in North Dakota, our most active area, which has production tax rates of up to 11.5% of crude oil revenues. Production taxes are generally based on the wellhead values of production and vary by state. Additionally, some states offer exemptions or reduced production tax rates for wells that produce less than a certain quantity of crude oil or natural gas and to encourage 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 increases to the statutory rate. Our overall production tax rate is expected to further increase as we continue to expand our operations in North Dakota and as production tax incentives we currently receive for horizontal wells reach the end of their incentive periods.

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

$/Boe	Three months ended September 30, 2011	2010
Production expenses	$ 5.98	$ 5.92
Production taxes and other expenses	6.44	4.65
Production expenses, production taxes and other expenses	$ 12.42	$ 10.57

Exploration Expenses. Exploration expenses consist primarily of dry hole costs and exploratory geological and geophysical costs that are expensed as incurred. Exploration expenses increased $6.3 million in the three months ended September 30, 2011 to $9.8 million due primarily to a $7.0 million increase in seismic expenses resulting from higher acquisitions of seismic data in the current year in connection with our increased capital budget for 2011. This increase was partially offset by a $1.1 million decrease in dry hole expenses.

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Depreciation, Depletion, Amortization and Accretion (DD&A). Total DD&A increased $42.2 million, or 67%, in the third quarter of 2011 compared to the third quarter of 2010, primarily due to a 48% increase in production volumes. The following table shows the components of our DD&A on a unit of sales basis.

	Three months ended September 30,	
$/Boe	**2011**	**2010**
Crude oil and natural gas	$ 16.83	$ 14.59
Other equipment	0.29	0.24
Asset retirement obligation accretion	0.13	0.16
Depreciation, depletion, amortization and accretion	$ 17.25	$ 14.99

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

Property Impairments. Property impairments increased in the three months ended September 30, 2011 by $11.5 million to $26.2 million compared to $14.7 million for the three months ended September 30, 2010.

Impairments of non-producing properties increased $3.9 million during the three months ended September 30, 2011 to $18.6 million compared to $14.7 million for the three months ended September 30, 2010, reflecting higher amortization of leasehold costs resulting from a larger base of amortizable costs. Non-producing properties consist of undeveloped leasehold costs and costs associated with the purchase of certain proved undeveloped reserves. Individually insignificant non-producing properties are amortized on an aggregate basis based on our estimated experience of successful drilling and the average holding period. We currently have no individually significant non-producing properties that are assessed for impairment on a property-by property basis.

Impairment provisions for proved crude oil and natural gas properties were $7.6 million for the three months ended September 30, 2011. We evaluate proved crude oil and natural gas properties for impairment by comparing their cost basis to the estimated future cash flows on a field basis. If the cost basis is in excess of estimated future cash flows, then we impair it based on an estimate of fair value based on discounted cash flows. Impairments of proved properties in 2011 primarily reflect uneconomic operating results for the first well drilled on our acreage in the Niobrara play in Colorado. No impairment provisions for proved properties were recognized for the three months ended September 30, 2010. For the 2010 period, future cash flows were determined to be in excess of cost basis, therefore no impairment was necessary.

General and Administrative Expenses. General and administrative expenses increased $6.0 million to $18.1 million during the three months ended September 30, 2011 from $12.1 million during the comparable period in 2010. On a volumetric basis, general and administrative expenses increased $0.08 to $2.98 per Boe for the three months ended September 30, 2011 compared to $2.90 per Boe for the three months ended September 30, 2010. General and administrative expenses include non-cash charges for stock-based compensation of $4.2 million and $2.6 million for the three months ended September 30, 2011 and 2010, respectively. General and administrative expenses excluding stock-based compensation increased $4.4 million for the three months ended September 30, 2011 compared to the same period in 2010. The increase was primarily related to an increase in personnel costs and office-related expenses associated with the growth of our Company. Over the past year, our Company has grown from having 470 total employees in September 2010 to 578 total employees in September 2011, a 23% increase. In March 2011, we announced plans to relocate our corporate headquarters from Enid, Oklahoma to Oklahoma City, Oklahoma. The move is a key element of our growth strategy of tripling our production and reserves between 2009 and 2014 and is expected to be completed during 2012. For the three months ended September 30, 2011, we have recognized approximately $1.1 million of costs in general and administrative expenses associated with the relocation. We currently expect to incur approximately $15 million to $25 million of costs in conjunction with the relocation, with the majority of such costs expected to be incurred in the second and third quarters of 2012.

Interest Expense. Interest expense increased $6.4 million, or 50%, for the three months ended September 30, 2011 compared to the three months ended September 30, 2010 due to increases in our weighted average outstanding long-term debt balance and our weighted average interest rate. Our weighted average interest rate for the three months ended September 30, 2011 was 7.6% with a weighted average outstanding long-term debt balance of $900.0 million compared to a weighted average interest rate of 6.2% with a weighted average outstanding long-term debt balance of $730.8 million for the same period in 2010. In September 2010, we issued $400 million of 7 $^{1}/_{8}$% Senior Notes and used a portion of the net proceeds to repay credit facility borrowings that carried lower interest rates.

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We had no outstanding borrowings on our revolving credit facility as of September 30, 2011 or during the three months then ended, while our weighted average outstanding revolving credit facility balance amounted to $170.0 million for the three months ended September 30, 2010.

Income Taxes. We recorded income tax expense for the three months ended September 30, 2011 of $270.5 million compared to $24.9 million for the three months ended September 30, 2010. We provide for income taxes at a combined federal and state tax rate of approximately 38% after taking into account permanent taxable differences.

Nine months ended September 30, 2011 compared to the nine months ended September 30, 2010

Results of Operations

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

	Nine months ended September 30,	
	2011	2010
	In thousands, except sales price data	
Crude oil and natural gas sales	$ 1,139,110	$ 675,376
Gain (loss) on derivative instruments, net [1]	372,490	57,626
Total revenues	1,535,671	747,686
Operating costs and expenses [2]	(606,638)	(370,478)
Other expenses, net	(54,212)	(31,854)
Income before income taxes	874,821	345,354
Provision for income taxes	(333,685)	(132,071)
Net income	$ 541,136	$ 213,283
Production volumes:		
Crude oil (MBbl) [3]	11,510	8,573
Natural gas (MMcf)	24,906	16,912
Crude oil equivalents (MBoe)	15,661	11,392
Sales volumes:		
Crude oil (MBbl) [3]	11,399	8,663
Natural gas (MMcf)	24,906	16,912
Crude oil equivalents (MBoe)	15,550	11,481
Average sales prices: [4]		
Crude oil ($/Bbl)	$ 88.19	$ 68.92
Natural gas ($/Mcf)	5.37	4.63
Crude oil equivalents ($/Boe)	73.25	58.82

(1) Amounts include unrealized non-cash mark-to-market gains on derivative instruments of $403.5 million and $28.2 million for the nine months ended September 30, 2011 and 2010, respectively.

(2) Net of gain on sale of assets of $15.4 million and $32.9 million for the nine months ended September 30, 2011 and 2010, respectively. In March 2011, we assigned certain non-strategic leaseholds in the state of Michigan to a third party for cash proceeds of $22.0 million and recognized a pre-tax gain on the transaction of $15.3 million in the first quarter of 2011. In June 2010, we sold certain non-strategic leaseholds located in Louisiana to a third party for cash proceeds of $35.4 million and recognized a pre-tax gain on the transaction of $31.7 million in the second quarter of 2010. These transactions involved undeveloped acreage with no proved reserves and no production or revenues.

(3) At various times we have stored crude oil due to pipeline line fill requirements, low commodity prices, or transportation constraints or we have sold crude oil from inventory. These actions result in differences between produced and sold crude oil volumes. Crude oil sales volumes were 111 MBbls less than crude oil production for the nine months ended September 30, 2011 and 90 MBbls more than crude oil production for the nine months ended September 30, 2010.

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

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Production

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

	Nine months ended September 30,					
	2011		2010		Volume	Percent
	Volume	Percent	Volume	Percent	increase	increase
Crude oil (MBbl)	11,510	73%	8,573	75%	2,937	34%
Natural Gas (MMcf)	24,906	27%	16,912	25%	7,994	47%
Total (MBoe)	15,661	100%	11,392	100%	4,269	37%

	Nine months ended September 30,				Volume	Percent
	2011		2010		increase	increase
	MBoe	Percent	MBoe	Percent	(decrease)	(decrease)
North Region	12,177	78%	8,969	79%	3,208	36%
South Region	3,179	20%	2,078	18%	1,101	53%
East Region	305	2%	345	3%	(40)	(12%)
Total	15,661	100%	11,392	100%	4,269	37%

Crude oil production volumes increased 34% during the nine months ended September 30, 2011 compared to the nine months ended September 30, 2010. Production increases in the North Dakota Bakken field and the Anadarko Woodford play contributed incremental production volumes in 2011 of 2,720 MBbls, an 88% increase over production in these areas for the same period in 2010. Production growth in these areas is primarily due to increased drilling activity and higher well completions resulting from our accelerated drilling program for 2011, which have offset the reduced production resulting from the abnormal rainfall and flooding experienced in North Dakota during the second quarter of 2011. Additionally, production in the Cedar Hills field increased 120 MBbls, or 4%, in 2011 due to new wells being completed and enhanced recovery techniques being successfully applied in this legacy field.

Natural gas production volumes increased 7,994 MMcf, or 47%, during the nine months ended September 30, 2011 compared to the same period in 2010. Natural gas production in the North Dakota Bakken field was up 2,186 MMcf, or 83%, for the nine months ended September 30, 2011 compared to the same period in 2010 due to new wells being completed and gas from existing wells being connected to natural gas processing plants in North Dakota. We expect natural gas production growth in North Dakota Bakken to be further enhanced by the increased capacity of natural gas processing plants in the play, which will enable us to deliver more natural gas to market. Natural gas production in the Anadarko Woodford play increased 5,171 MMcf, or 321%, due to additional wells being completed and producing in the nine months ended September 30, 2011 compared to the same period in 2010. Further, natural gas production increased 614 MMcf in non-Woodford areas of our South region due to the completion of new wells during the period.

Revenues

Our total revenues are comprised of sales of crude oil and natural gas, revenues associated with crude oil and natural gas service operations, and realized and unrealized changes in the fair value of our derivative instruments. Throughout 2010 and 2011 we entered into a series 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 accelerated drilling program over the next three years. Changes in commodity futures price strips during the nine months ended September 30, 2011 had an overall positive impact on the fair value of our derivative instruments, which resulted in positive revenue adjustments of $372.5 million for the period. The $372.5 million positive adjustment includes $403.5 million of unrealized non-cash mark-to-market gains on open derivative instruments partially offset by $31.0 million of realized losses during the period. The unrealized mark-to-market gain relates to derivative instruments with various terms that are scheduled to be realized over the period from October 2011 through December 2013. Over this period, actual realized derivative settlements may differ significantly from the unrealized mark-to-market valuation at September 30, 2011. 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.

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Crude Oil and Natural Gas Sales. Crude oil and natural gas sales for the nine months ended September 30, 2011 were $1,139.1 million, a 69% increase from sales of $675.4 million for the same period in 2010. Our sales volumes increased 4,069 MBoe, or 35%, over the same period in 2010 due to the continuing success of our drilling programs in the North Dakota Bakken field and Anadarko Woodford play. Our realized price per Boe increased $14.43 to $73.25 for the nine months ended September 30, 2011 from $58.82 for the nine months ended September 30, 2010. The differential between NYMEX calendar month average crude oil prices and our realized crude oil price per barrel for the nine months ended September 30, 2011 was $7.00 compared to $8.68 for the nine months ended September 30, 2010 and $9.02 for the year ended December 31, 2010. A significant portion of our operated crude oil production in the North region is being sold in markets other than Cushing, Oklahoma and is priced, apart from transportation costs, at a premium to West Texas Intermediate benchmark pricing, which has resulted in improved differentials.

Derivatives. We are required to recognize all derivative instruments on the balance sheet as either assets or liabilities measured at fair value. We have not designated our derivative instruments as hedges for accounting purposes. As a result, we mark our derivative instruments to fair value and recognize the realized and unrealized changes in fair value of derivative instruments in the unaudited condensed consolidated statements of income under the caption Gain (loss) on derivative instruments, net , which is a component of total revenues.

During the nine months ended September 30, 2011, we realized losses on crude oil derivatives of $54.9 million and realized gains on natural gas derivatives of $23.9 million. During the nine months ended September 30, 2011, we reported an unrealized non-cash mark-to-market gain on crude oil derivatives of $410.2 million and an unrealized non-cash mark-to-market loss on natural gas derivatives of $6.7 million. During the nine months ended September 30, 2010, we realized gains on crude oil derivatives of $15.2 million and natural gas derivatives of $14.3 million. During the nine months ended September 30, 2010, we reported an unrealized non-cash mark-to-market loss on crude oil derivatives of $0.3 million and an unrealized non-cash mark-to-market gain on natural gas derivatives of $28.4 million.

Crude Oil and Natural Gas Service Operations. Our crude oil and natural gas service operations consist primarily of the treatment and sale of lower quality crude oil, or reclaimed crude oil. The table below shows the volumes and prices for the sale of reclaimed crude oil for the periods presented.

	Nine months ended September 30,		
Reclaimed crude oil sales	**2011**	**2010**	**Increase**
Average sales price ($/Bbl)	$ 92.63	$ 74.29	$ 18.34
Sales volumes (barrels)	192,000	167,000	25,000

Prices for reclaimed crude oil sold from our central treating units were $18.34 per barrel higher for the nine months ended September 30, 2011 than the comparable 2010 period, which contributed to an increase in reclaimed crude oil revenue of $5.8 million to $17.8 million and contributed to an overall increase in crude oil and natural gas service operations revenue of $9.4 million for the nine months ended September 30, 2011. Also contributing to the increase in crude oil and natural gas service operations revenue was a $2.8 million increase in saltwater disposal income resulting from increased activity. Associated crude oil and natural gas service operations expenses increased $6.7 million to $19.7 million during the nine months ended September 30, 2011 from $13.0 million during the nine months ended September 30, 2010 due mainly to an increase in the costs of purchasing and treating reclaimed crude oil for resale and in providing saltwater disposal services.

Operating Costs and Expenses

Production Expenses and Production Taxes and Other Expenses. Production expenses increased 41% to $98.1 million during the nine months ended September 30, 2011 from $69.8 million during the nine months ended September 30, 2010. This increase is primarily the result of higher production volumes from an increase in the number of producing wells. Production expenses per Boe increased to $6.31 for the nine months ended September 30, 2011 from $6.08 per Boe for the nine months ended September 30, 2010. The per-unit increase was primarily due to increases in well site and road maintenance costs and saltwater disposal costs in the second quarter, all resulting from abnormal rainfall and flooding in North Dakota in April and May 2011. Also contributing to the per-unit increase were higher workover expenditures from increased activity as well as general inflationary pressure on the costs of oilfield services and equipment.

Production taxes and other expenses increased $46.6 million, or 87%, to $100.3 million during the nine months ended September 30, 2011 compared to the nine months ended September 30, 2010 as a result of higher crude oil and natural gas revenues resulting from increased commodity prices and sales volumes along with the expiration of various tax incentives. Production taxes and other expenses on the unaudited condensed consolidated statements of income include other charges for marketing, gathering,

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dehydration and compression fees primarily related to natural gas sales in the Oklahoma Woodford and North Dakota Bakken areas of $10.0 million and $3.9 million for the nine months ended September 30, 2011 and 2010, respectively. The increase in other charges is primarily due to the significant increase in natural gas sales volumes in the current year. Production taxes, excluding other charges, as a percentage of crude oil and natural gas revenues were 7.9% for the nine months ended September 30, 2011 compared to 7.4% for the nine months ended September 30, 2010. The increase is due to the expiration of various tax incentives coupled with higher taxable revenues in North Dakota, our most active area, which has production tax rates of up to 11.5% of crude oil revenues. Production taxes are generally based on the wellhead values of production and vary by state. Additionally, some states offer exemptions or reduced production tax rates for wells that produce less than a certain quantity of crude oil or natural gas and to encourage certain activities, such as horizontal drilling and enhanced recovery projects. In Montana and Oklahoma, new horizontal wells qualify for a tax incentive and are taxed at a lower rate during their initial months of production. After the incentive period expires, the tax rate increases to the statutory rate. Our overall production tax rate is expected to further increase as we continue to expand our operations in North Dakota and as production tax incentives we currently receive for horizontal wells reach the end of their incentive periods.

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

	Nine months ended September 30,	
$/Boe	**2011**	**2010**
Production expenses	$ 6.31	$ 6.08
Production taxes and other expenses	6.45	4.68
Production expenses, production taxes and other expenses	$ 12.76	$ 10.76

Exploration Expenses. Exploration expenses consist primarily of dry hole costs and exploratory geological and geophysical costs that are expensed as incurred. Exploration expenses increased $14.1 million in the nine months ended September 30, 2011 to $21.7 million due primarily to a $1.8 million increase in dry hole expenses and an $11.3 million increase in seismic expenses resulting from higher acquisitions of seismic data in the current year in connection with our increased capital budget for 2011.

Depreciation, Depletion, Amortization and Accretion. Total DD&A increased $89.9 million, or 52%, in the first nine months of 2011 compared to the first nine months of 2010 primarily due to a 37% increase in production volumes. The following table shows the components of our DD&A on a unit of sales basis.

	Nine months ended September 30,	
$/Boe	**2011**	**2010**
Crude oil and natural gas	$ 16.55	$ 14.78
Other equipment	0.29	0.24
Asset retirement obligation accretion	0.15	0.17
Depreciation, depletion, amortization and accretion	$ 16.99	$ 15.19

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

Property Impairments. Property impairments increased in the nine months ended September 30, 2011 by $16.9 million to $66.3 million compared to $49.4 million for the nine months ended September 30, 2010.

Impairments of non-producing properties increased $11.0 million during the nine months ended September 30, 2011 to $58.7 million compared to $47.7 million for the nine months ended September 30, 2010, reflecting higher amortization of leasehold costs resulting from a larger base of amortizable costs. Non-producing properties consist of undeveloped leasehold costs and costs associated with the purchase of certain proved undeveloped reserves. Individually insignificant non-producing properties are amortized on an aggregate basis based on our estimated experience of successful drilling and the average holding period. We currently have no individually significant non-producing properties that are assessed for impairment on a property-by-property basis.

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Impairment provisions for proved crude oil and natural gas properties were $7.6 million for the nine months ended September 30, 2011 compared to $1.7 million for the same period in 2010. We evaluate proved crude oil and natural gas properties for impairment by comparing their cost basis to the estimated future cash flows on a field basis. If the cost basis is in excess of estimated future cash flows, then we impair it based on an estimate of fair value based on discounted cash flows. Impairments of proved properties in 2011 primarily reflect uneconomic operating results for the first well drilled on our acreage in the Niobrara play in Colorado. Impairments in 2010 reflect uneconomic operating results in the East region and a non-Bakken Montana field in the North region.

General and Administrative Expenses. General and administrative expenses increased $16.2 million to $51.7 million during the nine months ended September 30, 2011 from $35.5 million during the comparable period in 2010. On a volumetric basis, general and administrative expenses increased $0.23 to $3.32 per Boe for the nine months ended September 30, 2011 compared to $3.09 per Boe for the nine months ended September 30, 2010. General and administrative expenses include non-cash charges for stock-based compensation of $11.7 million and $8.6 million for the nine months ended September 30, 2011 and 2010, respectively. General and administrative expenses excluding stock-based compensation increased $13.1 million for the nine months ended September 30, 2011 compared to the same period in 2010. The increase was primarily related to an increase in personnel costs and office-related expenses associated with the growth of our Company. Over the past year, our Company has grown from having 470 total employees in September 2010 to 578 total employees in September 2011, a 23% increase. In March 2011, we announced plans to relocate our corporate headquarters from Enid, Oklahoma to Oklahoma City, Oklahoma. The move is a key element of our growth strategy of tripling our production and reserves between 2009 and 2014 and is expected to be completed during 2012. For the nine months ended September 30, 2011, we have recognized approximately $1.5 million of costs in general and administrative expenses associated with the relocation. We currently expect to incur approximately $15 million to $25 million of costs in conjunction with the relocation, with the majority of such costs expected to be incurred in the second and third quarters of 2012.

Interest Expense. Interest expense increased $23.9 million, or 73%, for the nine months ended September 30, 2011 compared to the same period in 2010 due to increases in our weighted average outstanding long-term debt balance and our weighted average interest rate. Our weighted average interest rate for the nine months ended September 30, 2011 was 7.4% with a weighted average outstanding long-term debt balance of $923.7 million compared to a weighted average interest rate of 6.6% with a weighted average outstanding long-term debt balance of $612.1 million for the same period in 2010. We issued $200 million of 7 3/8% Senior Notes in April 2010 and $400 million of 7 1/8% Senior Notes in September 2010, the net proceeds of which were used to repay credit facility borrowings that carried lower interest rates.

Our weighted average outstanding revolving credit facility balance decreased to $23.7 million for the nine months ended September 30, 2011 compared to $161.2 million for the nine months ended September 30, 2010. The weighted average interest rate on our revolving credit facility borrowings was 2.65% for the nine months ended September 30, 2011 compared to 2.66% for the same period in 2010. At September 30, 2011, we had no outstanding borrowings on our revolving credit facility.

Income Taxes. We recorded income tax expense for the nine months ended September 30, 2011 of $333.7 million compared to $132.1 million for the nine months ended September 30, 2010. We provide for income taxes at a combined federal and state tax rate of approximately 38% after taking into account permanent taxable differences.

Liquidity and Capital Resources

Our primary sources of liquidity have been cash flows generated from operating activities, financing provided by our revolving credit facility and the issuance of debt and equity securities. During the first nine months of 2011, our average realized sales price was $14.43 per Boe higher than the first nine months of 2010. The increase in realized commodity prices in the current year, coupled with our 35% increase in sales volumes for the first nine months of 2011 compared to the same period in 2010, resulted in improved cash flows from operations and better liquidity. Further, our liquidity has improved in 2011 as we have more borrowing availability on our revolving credit facility as a result of repaying our credit facility borrowings through the issuance and sale of common stock in March 2011 as discussed below under the heading *Sale of Common Stock*.

At September 30, 2011, we had $42.3 million of cash and cash equivalents and $747.0 million of net available liquidity under our revolving credit facility after considering outstanding letters of credit.

Cash Flows

Cash Flows from Operating Activities

Our net cash provided by operating activities was $669.8 million and $495.3 million for the nine months ended September 30, 2011 and 2010, respectively. The increase in operating cash flows was primarily due to higher crude oil and natural gas revenues as a result of higher commodity prices and sales volumes, partially offset by an increase in realized losses on derivatives and increases in production expenses, production taxes, and other operating expenses associated with the growth of our operations in the current year.

Cash Flows from Investing Activities

During the nine months ended September 30, 2011 and 2010, we had cash flows used in investing activities (excluding asset sales) of $1,285.9 million and $747.6 million, respectively, related to our capital program, inclusive of dry hole costs. The increase in cash flows used in investing activities in 2011 was due to the continued acceleration of our drilling program, primarily in the North Dakota Bakken field and the Anadarko Woodford play in Oklahoma.

Cash Flows from Financing Activities

Net cash provided by financing activities for the nine months ended September 30, 2011 was $627.7 million and was the result of the issuance and sale of an aggregate 10,080,000 shares of our common stock in March 2011 for total net proceeds of $659.4 million, after deducting underwriting discounts and offering-related expenses, reduced by a net repayment of $30 million on our credit facility. Net cash provided by financing activities of $348.9 million for the nine months ended September 30, 2010 was mainly the result of receiving $587.2 million of net proceeds from the issuances of the 2020 Notes in April 2010 and the 2021 Notes in September 2010, reduced by net repayments of $226 million on our credit facility.

Future Sources of Financing

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

Based on our planned production growth and derivative contracts we have in place to limit the downside risk of adverse price movements associated with the forecasted sale of future production, we currently anticipate we will be able to generate or obtain funds sufficient to meet our short-term and long-term cash requirements. We intend to finance future capital expenditures primarily through cash flows from operations and through borrowings under our revolving credit facility, but we may also issue debt or equity securities or sell assets. The issuance of additional debt requires a portion of our cash flows from operations be used for the payment of interest and principal on our debt, thereby reducing our ability to use cash flows to fund working capital, capital expenditures and acquisitions. The issuance of additional equity securities could have a dilutive effect on the value of our common stock.

Sale of Common Stock

On March 9, 2011, we and certain selling shareholders completed a public offering of an aggregate of 10,000,000 shares of common stock, including 9,170,000 shares issued and sold by us 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). Our net proceeds from the offering amounted to approximately $599.7 million after deducting the underwriting discount and offering-related expenses. We did not receive any proceeds from the sale of shares by the selling shareholders. In connection with the offering, we 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, we completed the sale of an additional 910,000 shares of 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. We 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.

After deducting underwriting discounts and offering-related expenses, we received total net proceeds from the offering of $659.2 million, a portion of which was used to repay all amounts then outstanding under our revolving credit facility. The remaining net proceeds were used to fund a portion of our 2011 capital budget.

Revolving Credit Facility

We have a revolving credit facility with aggregate lender commitments totaling $750.0 million and a current borrowing base of $2.25 billion, subject to semi-annual redetermination. The most recent borrowing base redetermination was completed in October 2011, whereby the lenders approved an increase in the borrowing base from $2.0 billion to $2.25 billion. The aggregate commitment level may be increased at our option from time to time (provided no default exists) up to the lesser of $2.5 billion or the borrowing base then in effect. Borrowings under the facility bear interest, payable quarterly, at a rate per annum equal to the London Interbank Offered Rate (LIBOR) for one, two, three or six months, as elected by us, plus a margin ranging from 175 to 275 basis points, depending on the percentage of the borrowing base utilized, or the lead bank s reference rate (prime) plus a margin ranging from 75 to 175 basis points.

The commitments under our credit facility, which matures on July 1, 2015, are from a syndicate of 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 $750.0 million commitment.

We had no outstanding borrowings on our credit facility at September 30, 2011 and $30.0 million outstanding at December 31, 2010. As of September 30, 2011, we had $747.0 million of borrowing availability under our credit facility (after considering outstanding letters of credit). As previously discussed, we issued and sold an aggregate 10,080,000 shares of our common stock in March 2011 and received total net proceeds of $659.2 million after deducting underwriting discounts and offering-related expenses. The net proceeds were used to repay all borrowings then outstanding under our credit facility, which had a balance prior to payoff of $155.0 million, with the remaining net proceeds being used to fund a portion of our 2011 capital budget. As of October 31, 2011, we had $130.0 million of outstanding borrowings and $617.2 million of borrowing availability under our credit facility.

Our credit facility contains restrictive covenants that may limit our ability to, among other things, incur additional indebtedness, sell assets, make loans to others, make investments, enter into mergers, change material contracts, incur liens and engage in certain other transactions without the prior consent of the lenders. Our credit agreement also contains requirements that we maintain a current ratio of not less than 1.0 to 1.0 and a ratio of total funded debt to EBITDAX of no greater than 3.75 to 1.0. As defined by our credit agreement, the current ratio represents our ratio of current assets to current liabilities, inclusive of available borrowing capacity under the credit agreement and exclusive of current balances associated with derivative contracts and asset retirement obligations. EBITDAX represents earnings before interest expense, income taxes, depreciation, depletion, amortization and accretion, property impairments, exploration expenses, unrealized derivative gains and losses and non-cash equity compensation expense. EBITDAX is not a measure of net income or cash flows as determined by U.S. GAAP. A reconciliation of net income to EBITDAX is provided subsequently under the caption *Non-GAAP Financial Measures*. The total funded debt to EBITDAX ratio represents the sum of outstanding borrowings and letters of credit under our revolving credit facility plus our senior note obligations, divided by total EBITDAX for the most recent four quarters. We were in compliance with these covenants at September 30, 2011 and expect to maintain compliance for at least the next 12 months. We do not believe the restrictive covenants are reasonably likely to limit our ability to undertake additional debt or equity financing to a material extent.

In the future, we may not be able to access adequate funding under our credit facility as a result of (i) a decrease in our borrowing base due to the outcome of a subsequent borrowing base redetermination, or (ii) an unwillingness or inability on the part of our lending counterparties to meet their funding obligations. We expect the next borrowing base redetermination to occur in the second quarter of 2012. Declines in commodity prices could result in a determination to lower the borrowing base in the future and, in such case, we could be required to repay any indebtedness in excess of the borrowing base.

If we are unable to access funding when needed on acceptable terms, we may not be able to fully implement our business plans, complete new property acquisitions to replace our reserves, take advantage of business opportunities, respond to competitive pressures, or refinance our debt obligations as they come due, any of which could have a material adverse effect on our operations and financial results.

Derivative Activities

As part of our risk management program, we hedge a portion of our anticipated future crude oil and natural gas production to achieve more predictable cash flows and to reduce our exposure to fluctuations in crude oil and natural gas prices. Reducing our exposure to price volatility helps ensure adequate funds are available for our capital program. Our decision on the quantity and price at which we choose to hedge our future production is based in part on our view of current and future market conditions and our desire to have the cash flows needed to fund the development of our inventory of undeveloped crude oil and natural gas reserves in conjunction with our growth strategy. While the use of hedging arrangements limits the downside risk of adverse price movements, their use also limits future revenues from upward price movements. Substantially all of our hedging transactions are settled based upon reported settlement prices on the NYMEX.

We have hedged a significant portion of our forecasted production through 2013. Please see *Note 4. Derivative Instruments* in *Notes to Unaudited Condensed Consolidated Financial Statements* for further discussion of the accounting applicable to our derivative instruments, a summary of open contracts at September 30, 2011 and the estimated fair value of those contracts as of that date.

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Future Capital Requirements

Capital Expenditures

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

Our capital expenditure budget for 2011 is $2.0 billion, which is expected to be allocated as follows:

	Amount ***in millions***
Exploration and development drilling	$ 1,735
Land costs	165
Capital facilities, workovers and re-completions	53
Buildings, vehicles, computers and other equipment	32
Seismic	15
Total	$ 2,000

During the first nine months of 2011, we participated in the completion of 361 gross (124.6 net) wells and invested a total of $1,418.1 million in our capital program (including increases in accruals for capital expenditures of $117.8 million and $14.4 million of seismic costs) as shown in the following table.

	Amount ***in millions***
Exploration and development drilling	$ 1,169.7
Land costs	156.3
Capital facilities, workovers and re-completions	37.5
Buildings, vehicles, computers and other equipment	37.4
Acquisitions of producing properties	2.8
Seismic	14.4
Total	$ 1,418.1

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

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

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

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The 2012 capital plan will continue to focus primarily on increased development in the North Dakota Bakken field and Anadarko Woodford play. We plan to moderate our Bakken growth in 2012 and conserve capital while infrastructure is developed to accommodate industry growth in North Dakota, resulting in a decrease in our 2012 capital budget compared to 2011.

Although we cannot provide any assurance, assuming successful implementation of our strategy, including the future development of our proved reserves and realization of our cash flows as anticipated, we believe our remaining cash balance, cash flows from operations and available borrowing capacity under our revolving credit facility will be sufficient to fund our 2011 and 2012 capital budgets. The actual amount and timing of our capital expenditures may differ materially from our estimates as a result of, among other things, available cash flows, actual drilling results, the availability of drilling rigs and other services and equipment, and regulatory, technological and competitive developments.

Commitments

As of September 30, 2011, we had drilling rig contracts with various terms extending through August 2014. These contracts were entered into in the ordinary course of business to ensure rig availability to allow us to execute our business objectives in our key strategic plays. These drilling commitments are not recorded in the accompanying condensed consolidated balance sheets. Future drilling commitments as of September 30, 2011 total approximately $180 million, of which $49 million is expected to be incurred in 2011, $88 million in 2012, $27 million in 2013, and $16 million in 2014. We expect to continue to enter into additional drilling rig contracts to help mitigate the risk of experiencing equipment shortages and rising costs that could delay our drilling projects or cause us to incur expenditures not provided for in our capital budget.

We have an agreement with a third party whereby the third party will provide, on a take-or-pay basis, hydraulic fracturing services and related equipment to service certain of our properties in North Dakota and Montana. The agreement has a term of three years, beginning in October 2010, with two one-year extensions available at our discretion. Pursuant to the take-or-pay provisions, we will pay a fixed rate per day for a minimum number of days per calendar quarter over the three-year term regardless of whether or not the services are provided. Future commitments remaining at September 30, 2011 amount to approximately $45 million, of which $6 million is expected to be incurred in 2011, $22 million in 2012, and $17 million in 2013. The commitments under this agreement are not recorded in the accompanying condensed consolidated balance sheets. Since the inception of this agreement, we have been using the services more than the minimum number of days each quarter.

In, 2010, we entered into a five-year firm transportation commitment to guarantee capacity totaling 10,000 barrels of crude oil per day on a major pipeline in order to reduce the impact of possible production curtailments that may arise due to limited transportation capacity. The transportation commitment is for crude oil production in the Bakken field where we allocate a significant portion of our capital expenditures. The commitment requires us to pay transportation reservation charges of $1.85 per barrel, or $6.8 million annually, regardless of the amount of pipeline capacity used. Payments under the agreement began in the second quarter of 2011 in conjunction with the commencement of the pipeline system s operations. To date, production delivered to the pipeline system has exceeded the daily volumes provided in the contract. The commitments under this agreement are not recorded in the accompanying condensed consolidated balance sheets.

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

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

Corporate Relocation

In March 2011, we announced plans to relocate our corporate headquarters from Enid, Oklahoma to Oklahoma City, Oklahoma. The move is a key element of our growth strategy of tripling our production and reserves between 2009 and 2014. The relocation is expected to provide more convenient access to our operations across the country, to our business partners and to an expanded pool of technical talent. The transition is expected to be completed during 2012. We currently estimate we may incur approximately $15 million to $25 million of costs in conjunction with our relocation. These costs will be incurred over the next 15 months through the end of 2012, with the majority of such costs expected to be incurred in the second and third quarters of 2012. Over the next 15 months, we generally expect to recognize the majority of relocation costs in our financial statements when incurred. As of September 30, 2011, we have recognized approximately $1.5 million of costs associated with our relocation efforts, which are included in the caption General and administrative expenses in the unaudited condensed consolidated statements of income.

Critical Accounting Policies

There has been no change in our critical accounting policies from those disclosed in our Form 10-K for the year ended December 31, 2010.

Recent Accounting Pronouncements Not Yet Adopted

In May 2011, the Financial Accounting Standards Board (FASB) issued Accounting Standards Update (ASU) No. 2011-04, *Fair Value Measurement (Topic 820) Amendments to Achieve Common Fair Value Measurement and Disclosure Requirements in U.S. GAAP and IFRSs.* The amendments in ASU No. 2011-04 are the result of 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. We 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 our financial position, results of operations or cash flows.

We continue to closely monitor the joint standard-setting efforts of the FASB and the IASB. There are a number of pending accounting standards being targeted for completion in 2011 and beyond, including, but not limited to, standards relating to revenue recognition, accounting for leases, accounting for financial instruments, balance sheet offsetting, disclosure of loss contingencies and financial statement presentation. Because these pending standards have not yet been finalized, at this time we are not able to determine the potential future impact these standards will have, if any, on our financial position, results of operations or cash flows.

Non-GAAP Financial Measures

EBITDAX represents earnings before interest expense, income taxes, depreciation, depletion, amortization and accretion, property impairments, exploration expenses, unrealized derivative gains and losses, and non-cash equity compensation expense. EBITDAX is not a measure of net income or cash flows as determined by U.S. GAAP. Management believes EBITDAX is useful because it allows us to more effectively evaluate our operating performance and compare the results of our operations from period to period without regard to our financing methods or capital structure. We exclude the items listed above from net income in arriving at EBITDAX because these amounts can vary substantially from company to company within our industry depending upon accounting methods and book values of assets, capital structures and the method by which the assets were acquired. EBITDAX should not be considered as an alternative to, or more meaningful than, net income or cash flows as determined in accordance with U.S. GAAP or as an indicator of a company s operating performance or liquidity. Certain items excluded from EBITDAX are significant components in understanding and assessing a company s financial performance, such as a company s cost of capital and tax structure, as well as the historic costs of depreciable assets, none of which are components of EBITDAX. Our computations of EBITDAX may not be comparable to other similarly titled measures of other companies. We believe EBITDAX is a widely followed measure of operating performance and may also be used by investors to measure our ability to meet future debt service requirements, if any. Our revolving credit facility requires that we maintain a total funded debt to EBITDAX ratio of no greater than 3.75 to 1.0 on a rolling four-quarter basis. This ratio represents the sum of outstanding borrowings and letters of credit under our revolving credit facility plus our senior note obligations, divided by total EBITDAX for the most recent four quarters. We were in compliance with this covenant at September 30, 2011. A violation of this covenant in the future could result in a default under our revolving credit facility. In the event of such default, the lenders under our revolving 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 revolving 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 September 30,		**Nine months ended September 30,**	
in thousands	**2011**	**2010**	**2011**	**2010**
Net income	$ 439,143	$ 39,077	$ 541,136	$ 213,283
Interest expense	18,981	12,612	56,737	32,875
Provision for income taxes	270,488	24,904	333,685	132,071
Depreciation, depletion, amortization and accretion	105,085	62,918	264,236	174,327
Property impairments	26,225	14,698	66,315	49,387
Exploration expenses	9,814	3,530	21,660	7,585
Unrealized (gains) losses on derivatives	(536,227)	36,552	(403,471)	(28,162)

Non-cash equity compensation	4,245	2,626	11,742	8,596
EBITDAX	$ 337,754	$ 196,917	$ 892,040	$ 589,962

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 U.S. natural gas production. Pricing for crude oil and natural gas production has been volatile and unpredictable for several years, and we expect this volatility to continue in the future. The prices we receive for production depend on many factors outside of our control, including volatility in the differences between product prices at sales points and the applicable index prices. Based on our average daily production for the nine months ended September 30, 2011, and excluding any effect of our derivative instruments in place, our annual revenue would increase or decrease by approximately $154 million for each $10.00 per barrel change in crude oil prices and $33 million for each $1.00 per Mcf change in natural gas prices. To partially reduce price risk caused by these market fluctuations, we periodically hedge a portion of our anticipated crude oil and natural gas production as part of our risk management program and to provide greater certainty in our cash flows to support our capital expenditure program.

For the nine months ended September 30, 2011, we realized a net loss on crude oil and natural gas derivatives of $31.0 million and reported an unrealized non-cash mark-to-market gain on derivatives of $403.5 million. The fair value of our derivative instruments at September 30, 2011 was a net asset of $235.1 million. An assumed increase in the forward commodity prices used in the September 30, 2011 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 $55 million at September 30, 2011. Conversely, an assumed decrease in forward commodity prices of $10.00 per barrel for crude oil and $1.00 per MMBtu for natural gas would increase our net derivative asset to approximately $522 million at September 30, 2011.

Throughout 2010 and 2011 we entered into a series of derivative instruments, including fixed price swaps and zero-cost collars, to reduce the uncertainty of future cash flows in order to underpin our capital expenditures and our accelerated drilling program through 2013. Changes in commodity futures price strips during the nine months ended September 30, 2011 had an overall positive impact on the fair value of our derivative instruments, which resulted in the recognition of a $403.5 million unrealized mark-to-market gain on derivative instruments for the first nine months of 2011. The unrealized mark-to-market gain relates to derivative instruments with various terms that are scheduled to be realized over the period from October 2011 through December 2013. Over this period, actual realized derivative settlements may differ significantly, either positively or negatively, from the unrealized mark-to-market valuation at September 30, 2011.

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 ($301.6 million in receivables at September 30, 2011), our joint interest receivables ($358.9 million at September 30, 2011), and counterparty credit risk associated with our derivative instrument receivables ($235.1 million at September 30, 2011).

We monitor our exposure to counterparties on crude oil and natural gas sales primarily by reviewing credit ratings, financial statements and payment history. We extend credit terms based on our evaluation of each counterparty s credit worthiness. We have not generally required our counterparties to provide collateral to support crude oil and natural gas sales receivables owed to us. Historically, our credit losses on crude oil and natural gas sales receivables have been immaterial.

Joint interest receivables arise from billing entities which own a partial interest in the wells we operate. These entities participate in our wells primarily based on their ownership in leases included in units on which we wish to drill. We can do very little to choose who participates in our wells. In order to minimize our exposure to credit risk we generally request prepayment of drilling costs where it is allowed by contract or state law. For such prepayments, a liability is recorded and subsequently reduced as the associated work is performed. This liability was $74.2 million at September 30, 2011, which will be used to offset future capital costs when billed. In this manner, we reduce credit risk. We also have the right to place a lien on our co-owners interest in the well to redirect production proceeds in order to secure payment or, if necessary, foreclose on the interest. Historically, our credit losses on joint interest receivables have been immaterial.

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Our use of derivative instruments involves the risk that our counterparties will be unable to meet their commitments under the arrangements. We manage this risk by using multiple counterparties who we consider to be financially strong in order to minimize our exposure to credit risk with any individual counterparty. Currently, our derivative contracts are with parties that are lenders (or affiliates of lenders) under our revolving credit agreement.

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 revolving credit facility. We manage our interest rate exposure by monitoring both the effects of market changes in interest rates and the proportion of our debt portfolio that is variable-rate versus fixed-rate debt. We may utilize interest rate derivatives to alter interest rate exposure in an attempt to reduce interest rate expense related to existing debt issues. Interest rate derivatives may be used solely to modify interest rate exposure and not to modify the overall leverage of the debt portfolio. We currently have no interest rate derivatives. We had $130.0 million of outstanding borrowings under our revolving credit facility at October 31, 2011. The impact of a 1% increase in interest rates on this amount of debt would result in increased interest expense of approximately $1.3 million per year and a $0.8 million decrease in net income per year. Our revolving credit facility matures on July 1, 2015 and the weighted average interest rate at October 31, 2011 was 2.1%.

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 September 30, 2011. Disclosure controls and procedures include, without limitation, controls and procedures designed to provide reasonable assurance that the information required to be disclosed by us in the reports we file or submit under the Exchange Act is accumulated and communicated to our management, including our Chief Executive Officer and Chief Financial Officer, to allow timely decisions regarding required disclosures and is recorded, processed, summarized and reported within the time period in the rules and forms of the SEC.

Changes in Internal Control over Financial Reporting

During the quarter ended September 30, 2011, 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.

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PART II. Other Information

ITEM 1. Legal Proceedings

During the nine months ended September 30, 2011, there have been no material changes with respect to the legal proceedings previously disclosed in our 2010 Form 10-K that was filed with the SEC on February 25, 2011. See *Note 7. Commitments and Contingencies* in *Notes to Unaudited Condensed Consolidated Financial Statements* of this Form 10-Q.

ITEM 1A. Risk Factors

Except as set forth below, there have been no material changes in our risk factors from those disclosed in our 2010 Form 10-K.

In addition to the information set forth in this Form 10-Q, you should carefully consider the factors discussed in *Part I, Item 1A. Risk Factors* in our 2010 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 2010 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.

Our business depends on crude oil and natural gas transportation facilities, most of which are owned by third parties, and on the availability of rail transportation.

The marketability of our crude oil and natural gas production depends in part on the availability, proximity and capacity of pipeline and rail systems owned by third parties. The unavailability of, or lack of, available capacity on these systems and facilities could result in the shut-in of producing wells or the delay, or discontinuance of, development plans for properties. Although we have some contractual control over the transportation of our product, material changes in these business relationships could materially affect our operations. Federal and state regulation of crude oil and natural gas production and transportation, tax and energy policies, changes in supply and demand, pipeline pressures, damage to or destruction of pipelines and rail systems, labor disputes in the rail industry and general economic conditions could adversely affect our ability to produce, gather and transport crude oil and natural gas.

As a result of pipeline constraints and the continuous increase in Williston Basin production, we are transporting approximately 40% of the crude oil production from our North Region by rail. At October 31, 2011, eleven unions representing approximately 92,000 railway workers were unable to reach agreement on a new labor contract with more than 30 railroads. On October 6, 2011, President Obama appointed a Presidential Emergency Board to oversee contract talks, which effectively extends the period during which no job action is allowed for sixty days from that date or until early December 2011. In the event the relevant parties are unable to reach an agreement, a strike may occur in early December 2011.

The disruption of third-party pipelines or rail transportation facilities due to labor disputes, maintenance and/or weather could negatively impact our ability to market and deliver our products. We have no control over when or if such pipeline or rail facilities will be restored or what prices will be charged. A significant shut-in of production in connection with any of the aforementioned items could materially affect us due to a lack of cash flows, and if a substantial portion of the impacted production is hedged at lower than market prices, those financial hedges would have to be paid from borrowings absent sufficient cash flows.

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

(a) Not applicable.

(b) Not applicable.

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

The following table provides information about purchases of equity securities that are registered by us pursuant to Section 12 of the Exchange Act during the quarter ended September 30, 2011:

Period	Total number of shares purchased [(1)]	Average price paid per share [(2)]	Total number of shares purchased as part of publicly announced plans or programs	Maximum number of shares that may yet be purchased under the plans or program [(3)]
July 1, 2011 to July 31, 2011	711	$ 65.12		
August 1, 2011 to August 31, 2011	6,429	$ 64.04		
September 1, 2011 to September 30, 2011		$		
Total	7,140	$ 64.15		

(1) In connection with stock option exercises or restricted stock grants under the Continental Resources, Inc. 2000 Stock Option Plan (2000 Plan) and the Continental Resources, Inc. 2005 Long-Term Incentive Plan (2005 Plan), we adopted a policy that enables employees to surrender shares to cover their tax liability. All shares purchased above represent shares surrendered to cover tax liabilities. We paid the associated taxes to the Internal Revenue Service.

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

(3) We are unable to determine at this time the total amount of securities or approximate dollar value of those securities that could potentially be surrendered to us pursuant to our policy that enables employees to surrender shares to cover their tax liability associated with the exercise of options or vesting of restrictions on shares under the 2000 Plan and 2005 Plan.

ITEM 3. Defaults Upon Senior Securities

Not applicable.

ITEM 4. (Removed and Reserved)

ITEM 5. Other Information

Not applicable.

ITEM 6. Exhibits

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

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SIGNATURE

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

	CONTINENTAL RESOURCES, INC.
Date: November 3, 2011	By: /s/ John D. Hart John D. Hart Sr. Vice President, Chief Financial Officer and Treasurer (Duly Authorized Officer and Principal Financial Officer)

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Index to Exhibits

3.1	Third Amended and Restated Certificate of Incorporation 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 May 22, 2007 and incorporated herein by reference.
3.2	Second Amended and Restated Bylaws of Continental Resources, Inc. filed as Exhibit 3.2 to the Company s Current Report on Form 8-K (Commission File No. 001-32886) filed May 22, 2007 and incorporated herein by reference.
31.1*	Certification of the Company s Chief Executive Officer Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002 (15 U.S.C. Section 7241).
31.2*	Certification of the Company s Chief Financial Officer Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002 (15 U.S.C. Section 7241).
32**	Certification of the Company s Chief Executive Officer and Chief Financial Officer Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002 (18 U.S.C. Section 1350).
101.INS**	XBRL Instance Document
101.SCH**	XBRL Taxonomy Extension Schema Document
101.CAL**	XBRL Taxonomy Extension Calculation Linkbase Document
101.DEF**	XBRL Taxonomy Extension Definition Linkbase Document
101.LAB**	XBRL Taxonomy Extension Label Linkbase Document
101.PRE**	XBRL Taxonomy Extension Presentation Linkbase Document

* Filed herewith
** Furnished herewith