CONTINENTAL RESOURCES INC
Form 10-Q
May 06, 2010
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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 March 31, 2010

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 ¨ 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

169,967,432 shares of our $0.01 par value common stock were outstanding on April 30, 2010.

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

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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.

Bcf. One billion cubic feet of natural gas.

Boe. Barrels of crude oil equivalent, with six thousand cubic feet of natural gas being equivalent to one barrel of crude oil.

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

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.

Dry hole. A well found to be incapable of producing hydrocarbons in sufficient quantities such that proceeds from the sale of such production exceed production expenses and taxes.

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 often applied when production slows due to depletion of the natural pressure.

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.

FIF0. (First in/First out) A cost flow assumption where the first (oldest) costs are assumed to flow out first. This means the latest (recent) costs remain on hand.

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

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

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

Mcf. One thousand cubic feet of natural gas.

MBoe. One thousand Boe.

MMBoe. One million Boe.

MMBtu. One million British thermal units.

MMcf. One million cubic feet of natural gas.

MMMBtu. One billion British thermal units.

NYMEX. The New York Mercantile Exchange.

Play. A portion of the exploration and production cycle following the identification by geologists and geophysicists of areas with potential crude oil and natural gas reserves.

Proved reserves. These 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.

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.

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PART I. Financial Information

ITEM 1. Financial Statements

Continental Resources, Inc. and Subsidiary

Condensed Consolidated Balance Sheets

	March 31, 2010 (Unaudited)	December 31, 2009
	In thousands, except par values and share data	
Assets		
Current assets:		
Cash and cash equivalents	$ 14,658	$ 14,222
Receivables:		
Crude oil and natural gas sales	148,390	119,565
Affiliated parties	8,966	7,823
Joint interest and other, net	87,046	55,970
Derivatives	16,590	2,218
Inventories	27,074	26,711
Deferred and prepaid taxes		4,575
Prepaid expenses and other	4,082	4,944
Total current assets	306,806	236,028
Net property and equipment, based on successful efforts method of accounting	2,187,068	2,068,055
Debt issuance costs, net	10,043	10,844
Noncurrent derivatives receivable	3,917	
Total assets	$ 2,507,834	$ 2,314,927
Liabilities and shareholders equity		
Current liabilities:		
Accounts payable trade	$ 177,876	$ 91,248
Accounts payable trade to affiliated parties	15,873	9,612
Accrued liabilities and other	62,175	49,601
Revenues and royalties payable	74,363	66,789
Current portion of asset retirement obligation	2,721	2,460
Total current liabilities	333,008	219,710
Long-term debt	495,565	523,524
Other noncurrent liabilities:		
Deferred tax liability	521,351	489,241
Asset retirement obligation, net of current portion	47,920	47,707
Other noncurrent liabilities	4,504	4,466
Total other noncurrent liabilities	573,775	541,414
Commitments and contingencies (Note 7)		
Shareholders equity:		
Preferred stock, $0.01 par value: 25,000,000 shares authorized; no shares issued and outstanding		
	1,700	1,700

Common stock, $0.01 par value; 500,000,000 shares authorized, 169,972,597 shares issued and outstanding at March 31, 2010; 169,968,471 shares issued and outstanding at December 31, 2009				
Additional paid-in-capital		433,025		430,283
Retained earnings		670,761		598,296
Total shareholders equity		1,105,486		1,030,279
Total liabilities and shareholders equity	$	2,507,834	$	2,314,927

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

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Continental Resources, Inc. and Subsidiary

Unaudited Condensed Consolidated Statements of Operations

	Three Months Ended March 31, 2010	2009
	In thousands, except per share data	
Revenues:		
Oil and natural gas sales	$ 208,059	$ 85,817
Oil and natural gas sales to affiliates	9,065	6,751
Gain on mark-to-market derivative instruments	26,344	
Oil and natural gas service operations	4,800	4,040
Total revenues	248,268	96,608
Operating costs and expenses:		
Production expenses	19,159	17,274
Production expense to affiliates	3,442	5,152
Production tax and other expenses	16,007	6,822
Exploration expense	1,786	7,119
Oil and natural gas service operations	3,956	2,403
Depreciation, depletion, amortization and accretion	52,587	50,697
Property impairments	15,175	35,425
General and administrative	11,849	10,284
Gain on sale of assets	(222)	(136)
Total operating costs and expenses	123,739	135,040
Income (loss) from operations	124,529	(38,432)
Other income (expense):		
Interest expense	(8,360)	(4,587)
Other	706	147
Net other income (expense)	(7,654)	(4,440)
Income (loss) before income taxes	116,875	(42,872)
Provision (benefit) for income taxes	44,410	(16,259)
Net income (loss)	$ 72,465	$ (26,613)
Basic net income (loss) per share	$ 0.43	$ (0.16)
Diluted net income (loss) per share	$ 0.43	$ (0.16)

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

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Continental Resources, Inc. and Subsidiary

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, January 1, 2009	169,558,129	$ 1,696	$ 420,054	$ 526,958	$ 948,708
Net income				71,338	71,338
Stock-based compensation			11,408		11,408
Tax benefit on stock-based compensation plan			2,872		2,872
Stock options:					
Exercised	138,010	1	244		245
Repurchased and canceled	(29,924)		(1,223)		(1,223)
Restricted stock:					
Issued	411,217	4			4
Repurchased and canceled	(83,457)	(1)	(3,072)		(3,073)
Forfeited	(25,504)				
Balance, December 31, 2009	169,968,471	$ 1,700	$ 430,283	$ 598,296	$ 1,030,279
Net income (unaudited)				72,465	72,465
Stock-based compensation (unaudited)			2,852		2,852
Stock options:					
Exercised (unaudited)	4,500		3		3
Restricted stock:					
Issued (unaudited)	21,723				
Repurchased and canceled (unaudited)	(2,690)		(113)		(113)
Forfeited (unaudited)	(19,407)				
Balance, March 31, 2010 (unaudited)	169,972,597	$ 1,700	$ 433,025	$ 670,761	$ 1,105,486

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

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Continental Resources, Inc. and Subsidiary

Unaudited Condensed Consolidated Statements of Cash Flows

	Three months ended March 31, 2010	2009
	In thousands	
Cash flows from operating activities:		
Net income (loss)	$ 72,465	$ (26,613)
Adjustments to reconcile net income (loss) to net cash provided by operating activities:		
Depreciation, depletion, amortization and accretion	52,179	54,257
Property impairments	15,175	35,425
Change in derivative fair value	(22,052)	
Stock-based compensation	2,852	2,717
Provision (benefit) for deferred income taxes	40,416	(16,259)
Dry hole costs	33	4,763
Other, net	734	344
Changes in assets and liabilities:		
Accounts receivable	(61,044)	54,140
Inventories	(363)	(16,458)
Prepaid expenses and other	4,030	1,884
Accounts payable trade	69,719	(19,518)
Revenues and royalties payable	7,574	(25,785)
Accrued liabilities and other	8,932	(10,182)
Other noncurrent liabilities	38	1,388
Net cash provided by operating activities	190,688	40,103
Cash flows from investing activities:		
Exploration and development	(156,625)	(206,308)
Purchase of oil and natural gas properties	(128)	(350)
Purchase of other property and equipment	(6,263)	(440)
Proceeds from sale of assets	1,106	765
Net cash used in investing activities	(161,910)	(206,333)
Cash flows from financing activities:		
Revolving credit facility borrowings	44,000	191,600
Repayment of revolving credit facility	(72,000)	(24,000)
Debt issuance costs	(232)	(1,220)
Repurchase of equity grants	(113)	(67)
Dividends to shareholders		(2)
Exercise of options	3	5
Net cash (used in) provided by financing activities	(28,342)	166,316
Net change in cash and cash equivalents	436	86
Cash and cash equivalents at beginning of period	14,222	5,229
Cash and cash equivalents at end of period	$ 14,658	$ 5,315

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

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Continental Resources, Inc. and Subsidiary

Notes to Unaudited Condensed Consolidated Financial Statements

Note 1. Organization and Nature of Business

Description of Company

Continental Resources, Inc. s principal business is crude oil and natural gas exploration, development and production. Continental s operations are primarily in the North, South, and East regions of the United States.

Note 2. Basis of Presentation and Significant Accounting Policies

Basis of presentation

This report has been prepared pursuant to the rules and regulations of the Securities and Exchange Commission (SEC) applicable to interim financial information. Because this is an interim period filing presented using a condensed format, it does not include all of the disclosures required by accounting principles generally accepted in the United States (U.S. GAAP), although the Company believes that the disclosures are adequate to make the information not misleading. You should read this Form 10-Q along with the Company s Annual Report on Form 10-K for the year ended December 31, 2009 (2009 Form 10-K), which includes a summary of the Company s significant accounting policies and other disclosures.

The financial statements as of March 31, 2010 and for the three month periods ended March 31, 2010 and 2009 are unaudited. The Condensed Consolidated Balance Sheet as of December 31, 2009 was derived from the audited balance sheet filed in the 2009 Form 10-K. The Company has evaluated events or transactions through the date this report on Form 10-Q was filed 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 accounting principles generally accepted in the United States of America 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. Inventories consist of the following:

In thousands	**March 31, 2010**	**December 31, 2009**
Tubular goods and equipment	$ 12,364	$ 12,044
Crude oil	14,710	14,667
	$ 27,074	$ 26,711

As of March 31, 2010, our total crude oil inventory of 347,000 barrels valued at $14.7 million consisted of approximately 267,000 barrels of line fill requirements and 80,000 barrels of temporarily stored crude oil. As of December 31, 2009, our total crude oil inventory of 398,000 barrels valued at $14.7 million consisted of approximately 253,000 barrels of line fill requirements and 145,000 barrels of temporarily stored crude oil. Inventories, including line fill, are valued at the lower of cost or market using the FIFO inventory method.

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Earnings per common share

Basic earnings per common share is computed by dividing net income (loss) by the weighted-average number of shares outstanding for the period. Diluted earnings 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 these awards and options were exercised. The following is the calculation of basic and diluted weighted average shares outstanding and income (loss) per share computations for the three months ended March 31, 2010 and 2009:

	Three months ended March 31,	
In thousands, except per share data	**2010**	**2009**
Income (loss) (numerator):		
Net income (loss) - basic and diluted	$ 72,465	$ (26,613)
Weighted average shares (denominator):		
Weighted average shares - basic	168,855	168,467
Restricted shares	662	
Employee stock options	303	
Weighted average shares - diluted	169,820	168,467
Income (loss) per share:		
Basic	$ 0.43	$ (0.16)
Diluted	$ 0.43	$ (0.16)

The potential dilutive effect of 316,000 weighted average restricted shares and 420,000 weighted average stock options were not considered in diluted income (loss) per share for the three months ended March 31, 2009, because to do so would have been anti-dilutive.

New accounting standards

In January 2010, the FASB issued ASU No. 2010-06, *Fair Value Measurements and Disclosures (Topic 820) Improving Disclosures about Fair Value Measurements*, which requires new disclosures and clarifies existing disclosure requirements related to fair value measurements. The new standard requires additional disclosures related to (i) the amounts of significant transfers between Level 1 and Level 2 fair value measurements and the reasons for the transfers, (ii) the reasons for any transfers in or out of Level 3 measurements, and (iii) the presentation of information in the rollforward of recurring Level 3 measurements about purchases, sales, issuances, and settlements on a gross basis. The new standard is effective for interim and annual reporting periods beginning after December 15, 2009, except for the disclosure requirements related to the gross presentation of purchases, sales, issuances, and settlements in the Level 3 rollforward. Those disclosures are effective for fiscal years beginning after December 15, 2010. The Company adopted the applicable provisions of this new standard on January 1, 2010 and has included the required disclosures in *Note 5 Fair Value Measurements.*

Reclassifications

Certain prior year amounts have been reclassified on the condensed consolidated financial statements to conform to the 2010 presentation. On the condensed consolidated balance sheets as of December 31, 2009, the line item Derivatives was included in Joint interest and other, net and has been shown separately in this report to conform to the 2010 presentation.

Note 3. Supplemental Cash Flow Information

Net cash provided by operating activities reflects cash interest payments of $2.3 million for the three months ended March 31, 2010 and $4.5 million for the three months ended March 31, 2009. During the three months ended March 31, 2010, the Company received cash payments of $1.3 million for refunds of income taxes paid. During the three months ended March 31, 2009, the Company received cash payments of $1.9 million for refunds of income taxes paid. Non-cash investing activities include asset retirement obligations of $0.5 million and $0.4 million for the three months ended March 31, 2010 and 2009, respectively.

Note 4. Derivative Contracts

The Company is required to recognize all derivative instruments on the balance sheet as either assets or liabilities measured at fair value. The Company elected not to designate its derivatives as cash flow hedges and as a result marked its derivative instruments to fair value and recognized the realized and unrealized change in fair value on derivative instruments in the statements of operations under the caption Gain on mark-to-market derivative instruments.

We have utilized swap and collar derivative contracts to hedge against the variability in cash flows associated with the forecasted sale of our 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 may limit future revenues from favorable price movements.

During the three months ended March 31, 2010, we entered into several new swap and collar derivative contracts covering a portion of our crude oil and natural gas production for 2010 and 2011. The new contracts were entered into in the normal course of business and we expect to enter into additional similar contracts during the year. None of the new contracts have been designated for hedge accounting.

With respect to a fixed price swap contract, the counterparty is required to make a payment to us if the settlement price for any settlement period is less than the swap price, and we are required to make 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 posted prices and those of our physical pricing points, we receive a payment from the counterparty if the settled price differential is greater than the stated terms of the contract and we pay 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 us if the settlement price for any settlement period is below the floor price, we are 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 equal to or greater than the floor price and equal to or less than the ceiling price.

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All of our derivative contracts are carried at their fair value on our consolidated balance sheets under the captions Receivables, Derivatives , Noncurrent derivatives receivable and Accrued liabilities and other. 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 our consolidated balance sheets. Substantially all of our 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 and the time value of options. The calculation of the fair value of collars requires the use of an option-pricing model. See *Note 5. Fair Value Measurements*.

At March 31, 2010, we had outstanding contracts with respect to our future production as set forth in the tables below that include the new swap and collar contracts entered into during the first quarter of 2010.

Crude Oil

			Collars			
		Swaps	Floors		Ceilings	
Period and Type of Contract	**Volume in MBbls**	**Weighted Average**	**Range**	**Weighted Average**	**Range**	**Weighted Average**
April 2010 - June 2010						
Swaps	865	$ 82.26				
Collars	910		$ 70-$78	$ 75.25	$ 88.75-$96.40	$ 92.23
July 2010 - December 2010						
Swaps	828	84.22				
Collars	2,760		$ 75-$78	76.00	$ 88.75-$96.75	93.43
January 2011 - March 2011						
Swaps	225	84.55				
Collars	765		$ 75-$80	76.47	$ 88.65-$95.00	90.66
April 2011 - December 2011						
Collars	2,338		$ 75-$80	77.94	$ 89.00-$89.35	89.21

Natural Gas

Period and Type of Contract	**Volume in MMMBtus**	**Swaps Weighted Average**
April 2010 - June 2010		
Swaps	3,757	$ 6.09
July 2010 - September 2010		
Swaps	3,778	6.09
October 2010 - December 2010		
Swaps	3,778	6.09
January 2011 - December 2011		
Swaps	11,863	6.36

Natural Gas Basis Centerpoint East

Period and Type of Contract	**Volume in MMMBtus**	**Swaps Weighted Average**
April 2010 - December 2010		
Basis swaps	5,400	$ (0.62)

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Derivative Fair Value Gain (Loss)

The following table presents information about the components of derivative fair value gain (loss) for the following periods presented. The Company did not have any derivative contracts at March 31, 2009 or for the three months ended March 31, 2009.

In thousands	Three months ended March 31, 2010
Realized gain (loss) on derivatives:	
Crude oil fixed price swaps	$ 2,531
Natural gas fixed price swaps	2,722
Natural gas basis swaps	(961)
Unrealized gain (loss) on derivatives:	
Crude oil fixed price swaps	(6,762)
Natural gas fixed price swaps	28,326
Natural gas basis swaps	488
Gain on mark-to-market derivative instruments	$ 26,344

The table below provides data about the fair value of derivatives that are not accounted for using hedge accounting. Our derivative contracts are carried at their fair value on our consolidated balance sheets under the captions Receivables, Derivatives , Noncurrent derivatives receivable and Accrued liabilities and other.

	March 31, 2010			December 31, 2009		
	Assets	(Liabilities)	Net	Assets	(Liabilities)	Net
In thousands	Fair Value	Fair Value	Fair Value	Fair Value	Fair Value	Fair Value
Commodity swaps and collars	$ 20,507	$ (544)	$ 19,963	$ 2,218	$ (4,307)	$ (2,089)

Note 5. Fair Value Measurements

In January 2010, the FASB issued ASU No. 2010-06, *Fair Value Measurements and Disclosures (Topic 820) Improving Disclosures about Fair Value Measurements*, which requires new disclosures and clarifies existing disclosure requirements related to fair value measurements. The Company adopted the applicable provisions of this new standard on January 1, 2010 and has included the required disclosures below, as applicable.

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

Assets and Liabilities Measured at Fair Value on a Recurring Basis

Certain assets and liabilities are reported at fair value on a recurring basis. The Company s assessment of the significance of a particular input to the fair value measurement requires judgment, and may affect the valuation of the fair value of our assets and liabilities and their placement within the fair value hierarchy levels. In determining the fair value of our fixed price and basis swaps, due to the unavailability of relevant comparable market data for our exact contracts, a discounted cash flow method is used. The discounted cash flow method estimates future cash flows based on quoted market prices for future commodity prices, observable inputs relating to basis differentials and a risk-adjusted discount rate. The fair value of fixed price and basis swap derivatives is calculated using mainly significant observable inputs (Level 2). The calculation of the fair value of our collar contracts requires the use of an option-pricing model with significant unobservable inputs (Level 3). The valuation models for derivative contracts are primarily industry-standard models that consider various inputs including: (a) quoted forward prices for commodities, (b) time value, (c) volatility factors, and (d) current market and contractual prices for the underlying instruments, as well as other relevant economic measures. The Company s calculation for each position is then compared to the counterparty valuation for reasonableness.

The following table summarizes the valuation of financial instruments by pricing levels that were accounted for at fair value on a recurring basis as of March 31, 2010. There were no transfers between Level 1 and Level 2 of the fair value hierarchy during the three months ended March 31, 2010. Further, there were no transfers in and/or out of Level 3 of the fair value hierarchy during the three months ended March 31, 2010.

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Description	Fair value measurements at March 31, 2010 using Level 1	Level 2	Level 3	Total
In thousands				
Derivative assets (liabilities):				
Fixed price swaps	$	$ 29,894	$	$ 29,894
Basis swaps		(2,107)		(2,107)
Collars			(7,824)	(7,824)
Total	$	$ 27,787	$ (7,824)	$ 19,963

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 period:

In thousands	2010
Balance at December 31, 2009	$ (3,275)
Total realized or unrealized gains (losses):	
Included in earnings	(4,549)
Included in other comprehensive income (loss)	
Purchases, sales, issuances and settlements, net	
Transfers into Level 3	
Transfers out of Level 3	
Balance at March 31, 2010	$ (7,824)
Change in unrealized gains (losses) relating to derivatives still held at March 31, 2010	$ (4,549)

Gains and losses (realized and unrealized) included in earnings for the three months ended March 31, 2010 attributable to the change in unrealized gains and losses relating to derivatives held at March 31, 2010 are reported in revenues.

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.

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. The discounted cash flow method estimates future cash flows based on management s expectations for the future and includes 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 crude oil and natural gas properties is calculated using significant unobservable inputs (Level 3). Higher amortization of lease costs in our existing fields, capital constraints, and amortization of new fields resulted in impairment of non-producing properties of $14.2 million and $9.4 million for the three months ended March 31, 2010 and 2009, respectively.

As a result of changes in reserves and the forward futures price strip, developed crude oil and natural gas properties were reviewed for impairment at March 31, 2010 and 2009 and the Company determined that the carrying amount of certain fields were not recoverable from future cash flows and, therefore, were impaired. The affected fields had no fair value at March 31, 2010, resulting in $1.0 million of developed property impairments for the three months ended March 31, 2010, which are recorded under the caption Property impairments in the condensed consolidated statements of operations. The affected fields at March 31, 2009, had fair value of $13.1 million, resulting in $26.0 million of developed property impairments for the first quarter of 2009.

Asset Retirement Obligations The fair value of asset retirement obligations (AROs) is estimated based on discounted cash flow projections using numerous estimates, assumptions and judgments regarding such factors as the existence of a legal obligation for an ARO; estimated probabilities, amounts and timing of settlements; the credit-adjusted risk-free rate to be used; and inflation rates. The fair value of ARO additions for the three months ended March 31, 2010 was $0.4 million, which is reflected in the caption Asset retirement obligation, 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 value of financial instruments that are not recorded at fair value in our condensed consolidated financial statements.

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In thousands	March 31, 2010 Carrying Amount	Fair Value	December 31, 2009 Carrying Amount	Fair Value
Long-term debt				
Revolving credit facility	$ 198,000	$ 198,000	$ 226,000	$ 226,000
8 1/4 % Senior Notes due 2019	297,565	318,870	297,524	315,750
Total	$ 495,565	$ 516,870	$ 523,524	$ 541,750

The fair value of the revolving credit facility approximates its carrying value based on the borrowing rates currently available to the Company for bank loans with similar terms and maturities. The fair value of the 8 1/4% Senior Notes due 2019 is based on quoted market prices.

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 these instruments.

Note 6. Long-term Debt

Long-term debt consists of the following:

In thousands	March 31, 2010	December 31, 2009
Revolving credit facility	$ 198,000	$ 226,000
8 1/4 % Senior Notes due 2019 (1)	297,565	297,524
Total long-term debt	$ 495,565	$ 523,524

(1) This amount is net of discounts on long-term debt of ($2.4) million and ($2.5) million at March 31, 2010 and December 31, 2009, respectively.

Revolving credit facility The Company had $198.0 million and $226.0 million in long-term debt outstanding at March 31, 2010 and December 31, 2009, respectively, on its revolving credit facility due April 11, 2011. 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 250 basis points, depending on the percentage of its borrowing base utilized, or the lead bank s reference rate (prime). The revolving credit facility has a maximum facility amount of $750.0 million and a borrowing base of $1.0 billion, subject to semi-annual re-determination. The commitment level was increased from $672.5 million to $750.0 million in June 2009. Under the terms of the revolving credit facility, the commitment level can be increased up to the lesser of the borrowing base or the note amount subject to bank agreement. The Company s weighted average interest rate on this debt was 2.15% at March 31, 2010.

The Company had $551.1 million of unused commitments under the revolving credit facility at March 31, 2010 and incurs commitment fees of 0.25% to 0.375% of the daily average excess of the commitment amount over the outstanding credit balance. The revolving credit facility contains certain covenants including that the Company maintain a Current Ratio of not less than 1.0 to 1.0 (inclusive of availability under the revolving credit facility) and a Total Funded Debt to EBITDAX, as such terms are defined in the credit agreement, of no greater than 3.75 to 1.0. The Company was in compliance with these covenants at March 31, 2010.

8 1/4% Senior Subordinated Notes due 2019 On September 23, 2009, the Company issued Senior Notes due 2019 (the Notes), which carry a coupon rate of 8.25% and were sold at a discount (99.16% of par), which equates to an effective yield to maturity of approximately 8.375%. The Company received net proceeds of approximately $289.7 million after deducting the underwriters discounts and offering expenses. The net proceeds were used to repay a portion of the borrowings outstanding under our revolving credit facility.

The Notes will mature on October 1, 2019, and interest is payable on the Notes on each April 1 and October 1, beginning April 1, 2010. The Company has the option to redeem all or a portion of the Notes at any time on or after October 1, 2014 at the redemption price specified in the Indenture dated September 23, 2009 (the Indenture) plus accrued and unpaid interest. The Company may also redeem the Notes, in whole or in part, at a make-whole redemption price specified in the Indenture, plus accrued and unpaid interest, at any time prior to October 1, 2014. In addition, the Company may redeem up to 35% of the Notes prior to October 1, 2012 under certain circumstances with the net cash proceeds from certain equity offerings. The Indenture contains certain restrictions on our ability to incur additional debt, pay dividends on our common stock, make investments, create liens on our assets, engage in transactions with our affiliates, transfer or sell assets, consolidate or merge, or sell substantially all of our assets. These covenants are subject to a number of important exceptions and qualifications. The Company was in compliance with these covenants as of March 31, 2010. The Notes are not subject to any sinking fund requirements. Our subsidiary, which currently has no independent assets or operations, fully and unconditionally guarantees this debt.

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Note 7. Commitments and Contingencies

Drilling Commitments. As of March 31, 2010, the Company had one drilling contract that expires in August 2011. This commitment is not recorded in the accompanying consolidated balance sheets. Future commitments as of March 31, 2010 are $12.3 million.

Employee retirement plan. The Company maintains a defined contribution retirement plan for its employees and makes discretionary contributions to the plan based on a percentage of each eligible employee s compensation. During the three months ended March 31, 2010 and the year ended December 31, 2009, contributions to the plan were 5% of eligible employees compensation, excluding bonuses. Expense for the three months ended March 31, 2010 and 2009 was $0.3 million.

Employee health claims. The Company self insures employee health claims up to the first $125,000 per employee. The Company self insures employee workers compensation claims up to the first $250,000 per employee. Any amounts paid above these are reinsured through third-party providers. The Company accrues for claims that have been incurred but not yet reported based on a review of claims filed versus expected claims based on claims history. At March 31, 2010 and December 31, 2009, the accrued liability for health and worker s compensation claims was $1.2 million and $1.3 million, respectively.

Litigation. The Company is involved in various legal proceedings in the normal course of business, none of which, in the opinion of management, will individually or collectively have a material adverse effect on the financial position or results of operations of the Company. As of March 31, 2010 and December 31, 2009, the Company has provided a reserve of $2.7 million for various matters, none of which are believed to be individually significant.

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

Note 8. Stock-Based Compensation

The Company has granted 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 included in general and administrative expense was $2.9 million for the three months ended March 31, 2010 and $2.7 million for the three months ended March 31, 2009.

Stock Options

Effective October 1, 2000, the Company adopted the 2000 Plan and granted 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 date of grant. On November 10, 2005, the 2000 Plan was terminated. As of March 31, 2010, options covering 2,005,973 shares had been exercised and 478,496 had been cancelled.

The Company s stock option activity under the 2000 Plan for the three months ended March 31, 2010 was as follows:

	Outstanding		Exercisable	
	Number of options	Weighted average exercise price	Number of options	Weighted average exercise price
Outstanding December 31, 2009	312,190	$ 1.06	312,190	$ 1.06
Exercised	(4,500)	0.71	(4,500)	0.71
Outstanding March 31, 2010	307,690	1.06	307,690	1.06

The intrinsic value of a stock option is the amount by which the value of the underlying stock exceeds the exercise price of the option at its exercise date. The total intrinsic value of options exercised during the three months ended March 31, 2010 was approximately $0.2 million. At March 31, 2010, all options were exercisable and had a weighted average remaining life of 1.1 years with an aggregate intrinsic value of $12.8 million.

Restricted Stock

On October 3, 2005, the Company adopted the 2005 Plan and reserved a maximum of 5,500,000 shares of common stock that may be issued pursuant to the 2005 Plan. As of March 31, 2010, the Company had 3,291,560 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 vest over periods ranging from one to three years.

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The Company began issuing shares of restricted common stock to employees and non-employee directors in October 2005. A summary of changes in the non-vested shares of restricted stock for the three months ended March 31, 2010, is presented below:

	Number of non-vested shares	Weighted average grant-date fair value
Non-vested restricted shares at December 31, 2009	1,126,821	$ 26.55
Granted	21,723	38.21
Vested	(21,006)	25.40
Forfeited	(19,407)	28.28
Non-vested restricted shares at March 31, 2010	1,108,131	26.77

The fair value of the restricted shares that vested during the three months ended March 31, 2010 at their vesting date was $0.9 million. As of March 31, 2010, there was $16.9 million of unrecognized compensation expense related to non-vested restricted shares. The expense is expected to be recognized over a weighted average period of 1.4 years.

Note 9. Subsequent Event

On April 5, 2010, the Company issued $200 million of 7 $^{3}/8$% Senior Notes due 2020 (the 2020 Notes). The 2020 Notes, which carry a coupon rate of 7.375%, were sold at a discount (99.105% of par), which equates to an effective yield to maturity of approximately 7.5%. The Company received net proceeds of approximately $194.2 million after deducting the initial purchasers discounts of approximately $1.8 million and initial purchasers fees of approximately $4.0 million. The net proceeds were used to repay a portion of the borrowings outstanding under our revolving credit facility.

The 2020 Notes will mature on October 1, 2020, and interest is payable on the 2020 Notes semi-annually on April 1 and October 1 of each year, commencing on October 1, 2010. The Company has the option to redeem all or a portion of the 2020 Notes at any time on or after October 1, 2015 at the redemption prices specified in the Indenture dated April 5, 2010 (the 2010 Indenture) plus accrued and unpaid interest. The Company may also redeem the 2020 Notes, in whole or in part, at a make-whole redemption price specified in the 2010 Indenture, plus accrued and unpaid interest, at any time prior to October 1, 2015. In addition, the Company may redeem up to 35% of the 2020 Notes prior to October 1, 2013 under certain circumstances with the net cash proceeds from certain equity offerings.

The 2010 Indenture contains certain restrictions on our ability to incur additional debt, pay dividends on our common stock, make certain investments, create certain liens on our assets, engage in certain transactions with our affiliates, transfer or sell certain assets, consolidate or merge, or sell substantially all of our assets. These covenants are subject to a number of important exceptions and qualifications. The 2020 Notes are not subject to any sinking fund requirements. Our sole subsidiary, which currently has no independent assets or operations, fully and unconditionally guarantees this debt.

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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 Act of 1995. All statements, other than statements of historical fact included in this report, regarding our strategy, future operations, financial position, estimated revenues and losses, projected costs, prospects, plans and objectives of management are forward-looking statements. When used in this report, the words could, believe, anticipate, intend, estimate, expect, project and similar expressions are to identify forward-looking statements, although not all forward-looking statements contain such identifying words. These forward-looking statements are based on our current expectations and assumptions about future events and are based on 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 Risk Factors included in our Annual Report on Form 10-K for the year ended December 31, 2009.

These forward-looking statements are based on management s current belief, based on currently available information, as to the outcome and timing of future events. Without limiting the generality of the foregoing, certain statements incorporated by reference or included in this report constitute forward-looking statements.

Forward-looking statements may include statements about our:

- business strategy;
- reserves;
- technology;
- financial strategy;
- crude oil and natural gas prices;
- timing and amount of future production of crude oil and natural gas;
- the amount, nature and timing of capital expenditures;
- drilling of wells;
- competition and government regulations;
- marketing of crude oil and natural gas;
- exploitation or property acquisitions;

- costs of exploiting and developing our properties and conducting other operations;
- general economic conditions;
- credit markets;
- liquidity and access to capital;
- uncertainty regarding 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 Risk Factors in this report, our Annual Report on Form 10-K for the year ended December 31, 2009, 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, all of which are expressly qualified by the statements in this section, to reflect events or circumstances after the date of this report.

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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, 2009. Our operating results for the periods discussed may not be indicative of future performance. Statements concerning future results are forward-looking statements.

Overview

We are engaged in crude oil and natural gas exploration, exploitation and production activities in the North, South and East regions of the United States. 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 operating income and revenues will primarily depend on product prices and our ability to increase our crude oil and natural gas production. In recent months and years, there has been significant volatility in crude oil and natural gas prices due to a variety of factors we cannot control or predict, including political and economic events, weather conditions, and competition from other energy sources. These factors impact supply and demand for crude oil and natural gas, which affects crude oil and natural gas prices. In addition, the prices we realize for our crude oil and natural gas production are affected by location differences in market prices.

For the first three months of 2010, our crude oil and natural gas production increased to 3,459 MBoe (38,428 Boe per day), up 146 MBoe, or 4% from the first three months of 2009. The increase in 2010 production was primarily driven by an increase in production from our Bakken field. Our crude oil and natural gas revenues for the first three months of 2010 increased 134% to $217.1 million due to a 108% increase in commodity prices compared to the same period in 2009. Our realized price per Boe increased $32.17 to $62.07 for the three months ended March 31, 2010 compared to the three months ended March 31, 2009. We experienced increases in production expense and production tax and other expenses of a combined total of $9.4 million, or 32%, due to an increase in production taxes as a result of increased commodity prices and an increase in workover expense. At various times, we have stored crude oil due to pipeline line fill requirements or because of low prices or we have sold crude oil from inventory. These actions result in differences between our produced and sold crude oil volumes. For the three months ended March 31, 2010, crude oil sales volumes were 40 MBbls more than crude oil production, and crude oil sales volumes were 216 MBbls less than crude oil production for the same period in 2009. Our cash flows from operating activities for the three months ended March 31, 2010, were $190.7 million, an increase of $150.6 million from $40.1 million provided by our operating activities during the comparable 2009 period. The increase in operating cash flows was primarily due to the increases in commodity prices. During the three months ended March 31, 2010, we invested $187.1 million (excluding increased accruals of $23.2 million and including $1.0 million seismic costs) in our capital program concentrating mainly in the North Dakota Bakken field, the Arkoma and Anadarko Woodford plays, and the Red River units.

Our 2010 capital expenditures budget of $850.0 million will primarily focus on increased development in the North Dakota Bakken, the Arkoma and Anadarko Woodford shale natural gas plays in Oklahoma and the Red River units, with total operated drilling rigs increasing to as many as 23 by mid-year 2010. We expect our cash flows from operations and the availability under our revolving credit facility will be sufficient to meet our capital expenditure needs. Continued strength in commodity prices may result in an increase in our actual capital expenditures during 2010; conversely, a significant decline in product prices could result in a decrease in our capital expenditures.

How We Evaluate Our Operations

We use a variety of financial and operational 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.

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

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	Three Months ended March 31, 2010	2009
Average daily production:		
Crude oil (Bopd)	29,121	26,578
Natural gas (Mcfd)	55,839	61,382
Crude oil equivalents (Boepd)	38,428	36,808
Average prices: (1)		
Crude oil ($/Bbl)	$ 71.41	$ 34.99
Natural gas ($/Mcf)	5.40	2.98
Crude oil equivalents ($/Boe)	62.07	29.90
Production expense ($/Boe) (1)	6.46	7.24
General and administrative expense ($/Boe) (1)	3.39	3.32
EBITDAX (in thousands) (2)	177,959	57,673
Net income (loss) (in thousands)	72,465	(26,613)
Diluted net income (loss) per share	0.43	(0.16)

(1) At various times, we have stored crude oil due to pipeline line fill requirements or because of low prices or we have sold crude oil from inventory. These actions result in differences between our produced and sold crude oil volumes. Crude oil sales volumes were 40 MBbls more than crude oil production for the three months ended March 31, 2010 and 216 MBbls less than crude oil production for the three months ended March 31, 2009. Average prices and per unit expenses have been calculated using sales volumes and excluding any effect of derivative transactions.

(2) EBITDAX represents earnings before interest expense, income taxes, depreciation, depletion, amortization and accretion, property impairments, exploration expense, unrealized derivative gains and losses and non-cash 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 header *Non-GAAP Financial Measures*.

Three months ended March 31, 2010 compared to the three months ended March 31, 2009

Results of Operations

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

In thousands, except volume price data	March 31, 2010	2009
Crude oil and natural gas sales	$ 217,124	$ 92,568
Gain on mark-to-market derivative instruments	26,344	
Total revenues	248,268	96,608
Operating costs and expenses	123,739	135,040
Other expense	7,654	4,440
Income (loss) before income taxes	116,875	(42,872)
Provision (benefit) for income taxes	44,410	(16,259)
Net income (loss)	$ 72,465	$ (26,613)
Production Volumes:		
Crude oil (MBbl)	2,621	2,392
Natural gas (MMcf)	5,026	5,524
Crude oil equivalents (MBoe)	3,459	3,313
Sales Volumes:		
Crude oil (MBbl)	2,661	2,176
Natural gas (MMcf)	5,026	5,524
Crude oil equivalents (MBoe)	3,499	3,096
Average Prices: (1)		
Crude oil ($/Bbl)	$ 71.41	$ 34.99

Natural gas ($/Mcf)	5.40	2.98
Crude oil equivalents ($/Boe)	62.07	29.90

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

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Production

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

	Three Months Ended March 31, 2010		2009		Volume increase	Percent increase
	Volume	Percent	Volume	Percent	(decrease)	(decrease)
Crude oil (MBbl)	2,621	76%	2,392	72%	229	10%
Natural Gas (MMcf)	5,026	24%	5,524	28%	(498)	(9)%
Total (MBoe)	3,459	100%	3,313	100%	146	4%

	Three Months Ended March 31, 2010		2009		Volume increase	Percent increase
	MBoe	Percent	MBoe	Percent	(decrease)	(decrease)
North Region	2,707	78%	2,441	74%	266	11%
South Region	628	18%	752	23%	(124)	(16)%
East Region	124	4%	120	3%	4	3%
Total (MBoe)	3,459	100%	3,313	100%	146	4%

Crude oil production volumes increased 10% during the three months ended March 31, 2010 compared to the three months ended March 31, 2009. Production increases in the North Dakota Bakken field and the Oklahoma Woodford contributed incremental volumes in 2010 of 360 MBbls in excess of production for the first quarter of 2009. Favorable results from drilling have been the primary contributors to production growth in these areas. This increase was partially offset by decreases in other areas. Natural gas volumes decreased 498 MMcf, or 9%, during the three months ended March 31, 2010 compared to the same period in 2009. Natural gas production in the Bakken field in the North region was up 460 MMcf for the three months ended March 31, 2010 compared to the same period in 2009 due to additional natural gas being connected and sold in North Dakota. These additional sales in North Dakota were offset by a decrease in natural gas volumes of 326 MMcf in the Red River units due to the Badlands plant being down for repairs. The South region natural gas volumes decreased mostly due to natural declines in the Arkoma Woodford play.

Revenues

Crude Oil and Natural Gas Sales. Crude oil and natural gas sales for the three months ended March 31, 2010 were $217.1 million, a 134% increase from sales of $92.6 million for the same period in 2009. Our sales volumes increased 403 MBoe, or 13%, over the same period in 2009 due to the continuing success of our enhanced crude oil recovery and drilling programs. Our realized price per Boe increased $32.17 to $62.07 for the three months ended March 31, 2010 from $29.90 for the three months ended March 31, 2009. The differential between NYMEX calendar month average crude oil prices and our realized crude oil price per barrel for the three months ended March 31, 2010 was $7.42 compared to $8.32 for the three months ended March 31, 2009, $9.30 for the fourth quarter 2009, and $8.29 for the year ended December 31, 2009. Factors contributing to the changing differentials included Canadian crude oil imports and increases in production in the North region, coupled with downstream transportation capacity and seasonal demand fluctuations for gasoline.

Derivatives. The Company is required to recognize all derivative instruments on the balance sheet as either assets or liabilities measured at fair value. We elected not to designate our derivatives as cash flow hedges. As a result, we marked our derivative instruments to fair value and recognized the realized and unrealized change in fair value on derivative instruments in the statements of operations under the caption Gain on mark-to-market derivative instruments.

During the three months ended March 31, 2010, we realized gains on natural gas derivatives of $1.8 million and realized gains on crude oil derivatives of $2.5 million. We reported an unrealized non-cash mark-to-market gain on natural gas derivatives of $28.8 million and an unrealized non-cash mark-to-market loss on crude oil derivatives of $6.8 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. Prices for reclaimed crude oil sold from our central treating units were higher for the three months ended March 31, 2010 than the comparable 2009 period. The price increased $36.03 per barrel which increased reclaimed crude oil income by $1.8 million contributing to an overall increase in crude oil and natural gas service operations revenue of $0.8 million for the three months ended March 31, 2010. Associated crude oil and natural gas service operations expenses increased $1.6 million to $4.0 million during the three months ended March 31, 2010 from $2.4 million during the three months ended March 31, 2009 due mainly to an increase in the costs of purchasing and treating crude oil for resale compared to the same period in 2009. We sold high-pressure air from our Red River units to a third party and recorded revenues of $0.7 million for the three months ended March 31, 2009. Beginning January 2010, we no longer sell high-pressure air to a third party.

Operating Costs and Expenses

Production Expense and Production Tax and Other Expenses. Production expense increased 1% to $22.6 million during the three months ended March 31, 2010 from $22.4 million during the three months ended March 31, 2009. Production expense per Boe decreased to $6.46 for the three months ended March 31, 2010 from $7.24 per Boe for the three months ended March 31, 2009 due to an increase in sales volumes as a result of drilling in the Bakken field.

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Production tax and other expenses increased $9.2 million, or 135%, during the three months ended March 31, 2010 compared to the three months ended March 31, 2009 as a result of higher revenues resulting from increased sales prices and the expiration of various tax incentives. Production tax and other expenses on the unaudited condensed consolidated statements of operations includes other charges for marketing, gathering, dehydration and compression fees primarily related to natural gas sales in the Arkoma area of $1.1 million and $1.3 million for the three months ended March 31, 2010 and 2009, respectively. Production tax, excluding other charges, as a percentage of crude oil and natural gas sales was 7.0% for the three months ended March 31, 2010 compared to 6.1% for the three months ended March 31, 2009. Production taxes are 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, North Dakota 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 rates. Our overall production tax rate is expected to increase as incentives we currently receive for horizontal wells reach the end of their incentive period.

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

	Three Months Ended March 31,		Increase
$/Boe	**2010**	**2009**	**(Decrease)**
Production expense	$ 6.46	$ 7.24	(11)%
Production tax and other expenses	4.58	2.20	108%
Production expense, production tax and other expenses	$ 11.04	$ 9.44	17%

Exploration Expense. Exploration expense consists primarily of dry hole costs and exploratory geological and geophysical costs that are expensed as incurred. Exploration expense decreased $5.3 million in the three months ended March 31, 2010 to $1.8 million due primarily to a decrease in dry hole expense of $4.7 million and geological research expense of $0.6 million.

Depreciation, Depletion, Amortization and Accretion (DD&A). Total DD&A increased $1.9 million, or 4% in the first quarter of 2010 compared to the first quarter of 2009, primarily due to the increase in production. The following table shows the components of our DD&A rate per Boe.

	Three Months Ended March 31,	
$/Boe	**2010**	**2009**
Crude oil and natural gas	$ 14.62	$ 15.95
Other equipment	0.23	0.25
Asset retirement obligation accretion	0.18	0.18
Depreciation, depletion, amortization and accretion	$ 15.03	$ 16.38

Property Impairments. Property impairments, non-producing and developed, decreased in the three months ended March 31, 2010 by $20.2 million to $15.2 million compared to $35.4 million during the three months ended March 31, 2009. Impairment of non-producing properties increased $4.8 million during the three months ended March 31, 2010 to $14.2 million compared to $9.4 million for the three months ended March 31, 2009 reflecting higher amortization of lease costs in our existing fields resulting from further defining likely drilling locations, capital constraints, and amortization of new fields. Non-producing properties consist of undeveloped leasehold costs and costs associated with the purchase of certain proved undeveloped reserves. Non-producing properties are amortized on a composite method based on our estimated experience of successful drilling and the average holding period.

Impairment provisions for developed crude oil and natural gas properties were approximately $1.0 million for the three months ended March 31, 2010 compared to approximately $26.0 million for the three months ended March 31, 2009, a decrease of $25.0 million, or 96%. We evaluate our developed 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 market value based on discounted cash flows. Impairments in 2010 reflect uneconomic operating results in a non-Bakken Montana field in the North region, which resulted in impairments of $1.0 million for the three months ended March 31, 2010. Impairments in 2009 reflect uneconomic drilling results in two single well fields completed in the first quarter of 2009 in our South region which resulted in impairments of $14.1 million. The remaining impairments were the result of decreases in reserves and prices.

General and Administrative Expense. General and administrative expense increased $1.5 million to $11.8 million during the three months ended March 31, 2010 from $10.3 million during the comparable period in 2009. The majority of the increase was in personnel and office expenses. General and administrative expense includes non-cash charges for stock-based compensation of $2.9 million and $2.7 million for the three months ended March 31, 2010 and 2009, respectively. General and administrative expense excluding stock-based compensation increased $1.3 million for the three months ended March 31, 2010 compared to the same period in 2009. On a volumetric basis, general and administrative expense increased $0.07 to $3.39 per Boe for the three months ended March 31, 2010 compared to $3.32 per Boe for the three months ended March 31, 2009.

Interest Expense. Interest expense increased 82%, or $3.8 million, for the three months ended March 31, 2010 compared to the three months ended March 31, 2009, due to increased interest rates and debt balances in 2010. On September 23, 2009, we issued $300.0 million of 8 1/4% Senior Notes due 2019 (the Notes). The Notes, which carry a coupon rate of 8.25%, were sold at a discount (99.16% of par), which equates to an effective yield to maturity of approximately 8.375%. We recorded $6.1 million in interest on the Notes for the three months ended March 31, 2010. Including the effect of the Notes, our weighted average interest rate for the three months ended March 31, 2010 was 6.05% while at March 31, 2010 our weighted average rate was 5.90%.

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Our average revolving credit facility balance decreased to $211.7 million for the three months ended March 31, 2010 compared to $473.5 million for the three months ended March 31, 2009, and the weighted average interest rate on our revolving credit facility was lower at 2.75% for the three months ended March 31, 2010 compared to 3.52% for the same period in 2009. At March 31, 2010 our outstanding revolving credit facility balance was $198.0 million with a weighted average interest rate of 2.15%.

Income Taxes. We recorded income tax expense for the three months ended March 31, 2010 of $44.4 million compared to an income tax benefit of $16.3 million for the three months ended March 31, 2009. We provide 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 the Notes in September 2009. During the second quarter of 2009, we began to see increases in crude oil prices to levels double the first quarter 2009 lows; however, natural gas prices remained depressed. Crude oil prices have continued to increase in 2010, whil