CONTINENTAL RESOURCES INC
Form 10-Q
August 07, 2009
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# UNITED STATES

# SECURITIES AND EXCHANGE COMMISSION

**Washington, D.C. 20549**

# FORM 10-Q

**(Mark One)**

x **QUARTERLY REPORT PURSUANT TO SECTION 13 OR 15 (d) OF THE SECURITIES EXCHANGE ACT OF 1934**
**For the quarterly period ended June 30, 2009**

**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

169,635,783 shares of our $0.01 par value common stock were outstanding on July 31, 2009.

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

*Completion*. The process of treating a drilled well followed by the installation of permanent equipment for the production of natural gas or 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 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.

*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.

*NYMEX*. The New York Mercantile Exchange.

*Proved reserves*. The estimated quantities of oil, natural gas and natural gas liquids which geological and engineering data demonstrate with reasonable certainty to be commercially recoverable in future years from known reservoirs under existing economic and operating conditions.

*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 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**

| | June 30, 2009 (Unaudited) | December 31, 2008 |
|---|---|---|
| | (In thousands, except share data) | |
| **Assets** | | |
| Current assets: | | |
| Cash and cash equivalents | $ 5,071 | $ 5,229 |
| Receivables: | | |
| Oil and natural gas sales | 100,562 | 63,659 |
| Affiliated parties | 6,596 | 14,914 |
| Joint interest and other, net | 69,888 | 150,506 |
| Inventories | 40,158 | 22,210 |
| Deferred and prepaid taxes | 2,982 | 18,810 |
| Prepaid expenses and other | 4,769 | 2,367 |
| Total current assets | 230,026 | 277,695 |
| Net property and equipment, based on successful efforts method of accounting | 1,990,046 | 1,935,143 |
| Debt issuance costs, net | 4,049 | 3,041 |
| Total assets | $ 2,224,121 | $ 2,215,879 |
| **Liabilities and shareholders equity** | | |
| Current liabilities: | | |
| Accounts payable trade | $ 104,930 | $ 260,188 |
| Accounts payable trade to affiliated parties | 13,000 | 25,730 |
| Accrued liabilities and other | 28,354 | 34,769 |
| Revenues and royalties payable | 58,165 | 78,160 |
| Current portion of asset retirement obligation | 2,770 | 4,747 |
| Total current liabilities | 207,219 | 403,594 |
| Long-term debt | 592,000 | 376,400 |
| Other noncurrent liabilities: | | |
| Deferred tax liability | 437,745 | 445,752 |
| Asset retirement obligation, net of current portion | 43,503 | 39,883 |
| Other noncurrent liabilities | 2,982 | 1,542 |
| Total other noncurrent liabilities | 484,230 | 487,177 |
| 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, 169,636,609 shares issued and outstanding at June 30, 2009; 169,558,129 shares issued and outstanding at December 31, 2008 | 1,696 | 1,696 |
| Additional paid-in capital | 425,123 | 420,054 |
| Retained earnings | 513,853 | 526,958 |
| Total shareholders equity | 940,672 | 948,708 |
| Total liabilities and shareholders equity | $ 2,224,121 | $ 2,215,879 |

*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 June 30, 2009 | Three Months Ended June 30, 2008 | Six Months Ended June 30, 2009 | Six Months Ended June 30, 2008 |
|---|---|---|---|---|
| | (In thousands, except per share data) | | (In thousands, except per share data) | |
| **Revenues:** | | | | |
| Oil and natural gas sales | $ 141,028 | $ 278,311 | $ 226,845 | $ 487,010 |
| Oil and natural gas sales to affiliates | 5,411 | 19,308 | 12,162 | 36,034 |
| Gain (loss) on mark-to-market derivative instruments | 890 | (3,358) | 890 | (7,966) |
| Oil and natural gas service operations | 4,432 | 9,173 | 8,472 | 16,007 |
| Total revenues | 151,761 | 303,434 | 248,369 | 531,085 |
| **Operating costs and expenses:** | | | | |
| Production expenses | 21,458 | 22,868 | 38,732 | 41,818 |
| Production expense to affiliates | 2,580 | 4,085 | 7,732 | 8,208 |
| Production tax and other expenses | 11,629 | 17,695 | 18,451 | 30,470 |
| Exploration expense | 1,530 | 5,731 | 8,649 | 10,993 |
| Oil and natural gas service operations | 2,694 | 6,468 | 5,097 | 10,698 |
| Depreciation, depletion, amortization and accretion | 53,148 | 28,062 | 103,845 | 56,708 |
| Property impairments | 23,275 | 3,153 | 58,700 | 7,673 |
| General and administrative | 9,351 | 10,276 | 19,635 | 17,807 |
| Gain on sale of assets | (85) | (133) | (221) | (212) |
| Total operating costs and expenses | 125,580 | 98,205 | 260,620 | 184,163 |
| Income (loss) from operations | 26,181 | 205,229 | (12,251) | 346,922 |
| Other income (expense): | | | | |
| Interest expense | (4,723) | (2,865) | (9,310) | (6,276) |
| Other | 301 | 248 | 448 | 547 |
| | (4,422) | (2,617) | (8,862) | (5,729) |
| Income (loss) before income taxes | 21,759 | 202,612 | (21,113) | 341,193 |
| Provision (benefit) for income taxes | 8,251 | 75,305 | (8,008) | 125,915 |
| Net income (loss) | $ 13,508 | $ 127,307 | $ (13,105) | $ 215,278 |
| Basic net income (loss) per share | $ 0.08 | $ 0.76 | $ (0.08) | $ 1.28 |
| Diluted net income (loss) per share | $ 0.08 | $ 0.75 | $ (0.08) | $ 1.27 |

*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, 2008 | 168,864,015 | $ 1,689 | $ 415,435 | $ 206,008 | $ 623,132 |
| Net income | | | | 320,950 | 320,950 |
| Stock-based compensation | | | 9,927 | | 9,927 |
| Stock options: | | | | | |
| Exercised | 436,327 | 4 | 1,438 | | 1,442 |
| Repurchased and canceled | (82,922) | (1) | (4,017) | | (4,018) |
| Restricted stock: | | | | | |
| Issued | 461,120 | 5 | | | 5 |
| Repurchased and canceled | (91,568) | (1) | (2,729) | | (2,730) |
| Forfeited | (28,843) | | | | |
| Balance, December 31, 2008 | 169,558,129 | $ 1,696 | $ 420,054 | $ 526,958 | $ 948,708 |
| Net loss (unaudited) | | | | (13,105) | (13,105) |
| Stock-based compensation (unaudited) | | | 5,422 | | 5,422 |
| Stock options: | | | | | |
| Exercised (unaudited) | 7,000 | | 5 | | 5 |
| Restricted stock: | | | | | |
| Issued (unaudited) | 109,496 | | | | |
| Repurchased and canceled (unaudited) | (14,012) | | (358) | | (358) |
| Forfeited (unaudited) | (24,004) | | | | |
| Balance, June 30, 2009 (unaudited) | 169,636,609 | $ 1,696 | $ 425,123 | $ 513,853 | $ 940,672 |

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

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**Continental Resources, Inc. and Subsidiary**

**Unaudited Consolidated Statements of Cash Flows**

| | Six months ended June 30, 2009 | Six months ended June 30, 2008 |
|---|---|---|
| | (In thousands) | |
| **Cash flows from operating activities:** | | |
| Net income (loss) | $ (13,105) | $ 215,278 |
| Adjustments to reconcile net income (loss) to net cash provided by operating activities: | | |
| Depreciation, depletion, amortization and accretion | 107,948 | 56,656 |
| Property impairments | 58,700 | 7,673 |
| Change in derivative fair value | (890) | (26,703) |
| Equity compensation | 5,422 | 3,895 |
| Tax benefit of excess non qualified stock option deduction | | (3,255) |
| Provision (benefit) for deferred income taxes | (8,008) | 100,811 |
| Dry hole costs | 4,992 | 1,646 |
| Others, net | 831 | 177 |
| **Changes in assets and liabilities:** | | |
| Accounts receivable | 52,033 | (112,675) |
| Inventories | (17,948) | (7,919) |
| Prepaid expenses and other | 13,523 | (336) |
| Accounts payable | (96,873) | 17,918 |
| Revenues and royalties payable | (19,995) | 18,217 |
| Accrued liabilities and other | (5,577) | 26,538 |
| Other noncurrent liabilities | 1,440 | 49 |
| Net cash provided by operating activities | 82,493 | 297,970 |
| **Cash flows from investing activities:** | | |
| Exploration and development | (296,099) | (275,504) |
| Purchase of oil and gas properties | (437) | (71,003) |
| Purchase of other property and equipment | (628) | (3,529) |
| Proceeds from sale of assets | 1,391 | 1,307 |
| Net cash used in investing activities | (295,773) | (348,729) |
| **Cash flows from financing activities:** | | |
| Revolving credit facility | 334,100 | 184,000 |
| Repayment of revolving credit facility | (118,500) | (129,000) |
| Debt issuance costs | (2,118) | (45) |
| Repurchase of equity grants | (358) | (4,177) |
| Dividends to shareholders | (7) | (6) |
| Exercise of options | 5 | 1,161 |
| Tax benefit of excess non qualified stock option deduction | | 3,255 |
| Net cash provided by financing activities | 213,122 | 55,188 |
| Net change in cash and cash equivalents | (158) | 4,429 |
| Cash and cash equivalents at beginning of period | 5,229 | 8,761 |
| Cash and cash equivalents at end of period | $ 5,071 | $ 13,190 |

*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 oil and natural gas exploration, development and production. Continental  s operations are primarily in the Rocky Mountain, Mid-Continent and Gulf Coast 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, 2008 (  2008 Form 10-K  ), which includes a summary of the Company  s significant accounting policies and other disclosures.

The financial statements as of June 30, 2009 and for the three and six month periods ended June 30, 2009 and 2008 are unaudited. The Condensed Consolidated Balance Sheet as of December 31, 2008 was derived from the audited balance sheet filed in the 2008 Form 10-K. The Company has evaluated events or transactions through August 5, 2009 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 oil and natural gas reserves, which is used to compute depreciation, depletion, amortization and impairment on producing oil and 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.

*Inventory*

Inventories are stated at the lower of cost or market. Inventory consists of the following (in thousands):

| | June 30, 2009 | December 31, 2008 |
|---|---|---|
| Tubular goods and equipment | $ 15,756 | $ 14,884 |
| Crude oil | 24,402 | 7,326 |
| | $ 40,158 | $ 22,210 |

Crude oil represents 669,000 barrels of crude oil at June 30, 2009 and 275,000 barrels of crude oil at December 31, 2008. The Company has entered into a series of physical delivery forward sale contracts that provide for the sale of stored crude oil in future months. The Company is currently scheduled to sell 248,200 barrels of currently stored crude oil to be delivered in the second half of 2009. Minimum pipeline line fill requirements resulted in inventory balances of 341,000 barrels and 230,000 barrels at June 30, 2009 and December 31, 2008, respectively, that were not currently available for sale.

*Earnings (loss) per common share*

Basic earnings per common share is computed by dividing net income 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 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 and six months ended June 30, 2009 and 2008:

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| | Three months ended June 30, 2009 | Three months ended June 30, 2008 | Six months ended June 30, 2009 | Six months ended June 30, 2008 |
|---|---|---|---|---|
| | (in thousands, except per share data) | | | |
| Income (loss) (numerator): | | | | |
| Net income (loss) - basic and diluted | $ 13,508 | $ 127,307 | $ (13,105) | $ 215,278 |
| Weighted average shares (denominator): | | | | |
| Weighted average shares - basic | 168,492 | 168,055 | 168,479 | 167,973 |
| Restricted shares | 584 | 643 | | 738 |
| Employee stock options | 422 | 854 | | 707 |
| Weighted average shares - diluted | 169,498 | 169,552 | 168,479 | 169,418 |
| Income (loss) per share: | | | | |
| Basic | $ 0.08 | $ 0.76 | $ (0.08) | $ 1.28 |
| Diluted | $ 0.08 | $ 0.75 | $ (0.08) | $ 1.27 |

The potential dilutive effect of 455,000 weighted average restricted shares and 421,000 weighted average stock options were not considered in diluted income (loss) per share for the six months ended June 30, 2009, because to do so would have been anti-dilutive.

*New accounting standards*

In December 2007, the FASB issued SFAS No. 141 (revised 2007), *Business Combinations* (SFAS 141(R)) and SFAS No. 160, *Noncontrolling Interests in Consolidated Financial Statements, an amendment of ARB No. 51* (SFAS 160). SFAS 141(R) changes how business acquisitions are accounted for and impacts financial statements both on the acquisition date and in subsequent periods. SFAS 160 changes the accounting and reporting for minority interests, which are re-characterized as noncontrolling interests and classified as a component of equity. SFAS 141(R) and SFAS 160 are effective for the Company for fiscal years beginning on or after December 15, 2008. SFAS 141(R) will be applied prospectively. SFAS 160 requires retroactive adoption of the presentation and disclosure requirements for existing minority interests. All other requirements of SFAS 160 will be applied prospectively. The adoption of SFAS 141(R) and SFAS 160 on January 1, 2009 did not have any impact on the Company s financial position or results of operations though it would impact financial reporting for any future acquisitions.

In February 2008, the FASB issued FASB Staff Position ( FSP ) FAS 157-2, *Effective Date of FASB Statement No. 157,* which provided a one year delay of the effective date of FAS 157 to January 1, 2009 for the Company for non-financial assets and non-financial liabilities, except those that are recognized or disclosed at fair value in the financial statements on a recurring basis (at least annually). Beginning January 1, 2009, the Company applied SFAS No. 157 to non-financial assets and liabilities. SFAS No. 157 applies to the Company s non-financial assets and liabilities in calculating fair value related to impairments of long-lived assets and asset retirement obligations. In both cases, SFAS No. 157 had no effect on these calculations. Both calculations are based primarily on level three inputs. The adoption of SFAS No. 157 did not have a material impact on the Company s financial position or results of operations.

In March 2008, the FASB issued SFAS No. 161, *Disclosures about Derivative Instruments and Hedging Activities-An amendment of FASB Statement No. 133,* which amends and expands the disclosure requirements of FAS 133 to require qualitative disclosure about objectives and strategies for using derivatives, quantitative disclosures about fair value amounts of gains and losses on derivative instruments, and disclosures about credit-risk-related contingent features in derivative agreements. The Company adopted the disclosure requirements of SFAS No. 161 beginning January 1, 2009. The adoption of this statement did not have an impact on the Company s financial position or results of operations.

In April 2009, the FASB issued two FSPs to provide additional application guidance and enhance disclosures regarding fair value measurements and impairments of securities.

FSP FAS 157-4, *Determining Fair Value When the Volume and Level of Activity for the Asset or Liability Have Significantly Decreased and Identifying Transactions That Are Not Orderly,* (FSP FAS 157-4) provides guidelines for making fair value measurements more consistent with the principles presented in SFAS No. 157. It also includes guidance on identifying circumstances that indicate a transaction is not orderly. The Company adopted FSP FAS 157-4 for the period ended June 30, 2009 and the adoption of this FSP did not have an impact on its financial position or results of operations.

FSP FAS 107-1 and APB 28-1, *Interim Disclosures about Fair Value of Financial Instruments*, (FSP FAS 107-1) requires that disclosures concerning the fair value of financial instruments be presented in interim as well as annual financial statements, which enhances consistency in financial reporting. The Company adopted the provisions of FSP FAS 107-1 for the period ended June 30, 2009. The adoption of FSP FAS 107-1 did not have an impact on its financial position or results of operations.

In May 2009, the FASB issued SFAS No. 165, *Subsequent Events* (SFAS No. 165). SFAS No. 165 establishes general standards of accounting for and disclosure of events that occur after the balance sheet date but before financial statements are issued or are available to be issued. Although there is new terminology, the standard is based on the same principles as those that currently exist. This statement, which includes a new required disclosure of the date through which an entity has evaluated subsequent events, is effective for interim or annual periods ending after June 15, 2009. The Company adopted SFAS No. 165 for the period ending June 30, 2009. The adoption of SFAS No. 165 did not have an impact on its financial position or results of operations.

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***Note 3. Cash Flow Information***

Net cash provided by operating activities reflects cash interest payments of $9.8 million for the six months ended June 30, 2009 and $5.8 million for the six months ended June 30, 2008. During the first quarter of 2009, the Company received cash payments of $1.9 million for refunds of income taxes paid. Non-cash investing and financing activities include asset retirement obligations of $0.6 million and $2.1 million for the six months ended June 30, 2009 and 2008, respectively.

***Note 4. Derivative Contracts***

SFAS No. 133, *Accounting for Derivative Instruments and Hedging Activities* requires recognition of 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 under the provisions of SFAS No. 133. As a result, the Company marked its derivative instruments to fair value in accordance with the provisions of SFAS No. 133 and recognized the realized and unrealized change in fair value on derivative instruments in the statement of operations.

In July 2007, the Company entered into fixed-price swap contracts covering 10,000 barrels of oil per day for the period from August 2007 through April 2008 to partially reduce price risk. During each month of the contract, the Company received a fixed-price of $72.90 per barrel and paid to the counterparties the average of the prompt NYMEX crude oil futures contract settlement prices for such month. These contracts expired in April 2008 and currently the Company s crude oil production remains unhedged.

In June 2009, the Company entered into natural gas fixed price swaps for 600,000 MMBtu per month at an average price of $5.80 per MMBtu for December 2009 and $6.30 per MMBtu for calendar year 2010. The Company also entered into basis swaps for the same volumes and periods to lock in the difference between NYMEX natural gas prices and Inside FERC Centerpoint Energy East Index at an average differential of ($0.53) per MMBtu for December 2009 and ($0.62) for calendar year 2010. These swaps were put in place to underpin the Company s current and expected level of operations in the Arkoma Woodford play in southeastern Oklahoma by securing a predictable cash flow stream on about a third of the Company s natural gas production for the periods covered.

*Derivative Fair Value Income (Loss)*

The following table presents information about the components of derivative fair value income (loss) for the following periods presented:

| (in thousands) | Three months ended June 30, 2009 | Three months ended June 30, 2008 | Six months ended June 30, 2009 | Six months ended June 30, 2008 |
|---|---|---|---|---|
| Realized gain (loss) on derivatives: | | | | |
| Crude oil fixed price swaps | $ | $ (11,869) | $ | $ (34,669) |
| Unrealized gain (loss) on derivatives | | | | |
| Crude oil fixed price swaps | | 8,511 | | 26,703 |
| Natural gas fixed price swaps | 1,835 | | 1,835 | |
| Natural gas basis swaps | (945) | | (945) | |
| Derivative fair value income (loss) | $ 890 | $ (3,358) | $ 890 | $ (7,966) |

The Company adopted SFAS No. 161 in January 2009 and the expanded disclosures required are presented below. The table below provides data about the carrying values of derivatives that do not qualify for hedge accounting.

| | June 30, 2009 | | | December 31, 2008 | | |
|---|---|---|---|---|---|---|
| (in thousands) | Assets Carrying Value | (Liabilities) Carrying Value | Net Carrying Value | Assets Carrying Value | (Liabilities) Carrying Value | Net Carrying Value |
| Derivative that do not qualify for hedge accounting: | | | | | | |
| Fixed price swaps | $ 1,835 | $ | $ 1,835 | $ | $ | $ |
| Basis swaps | | (945) | (945) | | | |

| | | | | | |
|---|---|---|---|---|---|
| $ 1,835 | $ (945) | $ 890 | $ | $ | $ |

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***Note 5. Fair Value Measures***

SFAS No. 157 establishes a fair value 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. The Company uses Level 1 inputs when available as Level 1 inputs generally provide the most reliable evidence of fair value.

*Assets and Liabilities Measured at Fair Value on a Recurring Basis*

Under SFAS No.157, certain assets and liabilities are reported at fair value on a recurring basis. The Company s assessment of the significance of a particular input to the fair value measurement requires judgment, and may affect the valuation of the fair value of assets and liabilities and their placement within the fair value hierarchy levels. In determining the fair value of its 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 derivatives is calculated using mainly significant observable inputs (Level 2).The Company s calculation is then compared to the counterparty valuation for reasonableness. The following table summarizes the valuation of investments and financial instruments by SFAS No. 157 pricing levels as of June 30, 2009:

| | Fair value measurements using | | | |
|---|---|---|---|---|
| **Description** | **Level 1** | **Level 2** | **Level 3** | **Total** |
| | | **(In thousands)** | | |
| Derivatives: | | | | |
| Fixed price swaps | $ | $ 1,835 | $ | $ 1,835 |
| Basis swaps | $ | $ (945) | $ | $ (945) |

*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 consolidated balance sheets. The following methods and assumptions were used to estimate the fair values:

*Asset Impairments* In accordance with SFAS No. 144, *Accounting for the Impairment or Disposal of Long-Lived Assets,* proved oil and 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 oil and gas production, commodity prices based on commodity futures price strips, operating and development costs, and a risk-adjusted discount rate. The fair value of oil and gas properties is calculated using significant unobservable inputs (Level 3).

As a result of changes in reserves and the forward futures price strip, developed oil and gas properties were reviewed for impairment at June 30, 2009. The Company determined that the carrying amount of certain fields were not recoverable from future cash flows and, therefore, were impaired at June 30, 2009. The affected fields had a fair value of $1.8 million at June 30, 2009 resulting in $10.1 million of developed property impairments for the quarter ended June 30, 2009. A similar calculation at March 31, 2009 determined that the carrying amount of certain fields was not recoverable from future cash flows and, therefore, was impaired. The affected fields at March 31, 2009 had a fair value of $13.1 million resulting in $26.0 million of developed property impairments for first quarter of 2009. Total pre-tax (non-cash) impairments related to developed oil and gas properties for first half of 2009 were $36.1 million.

*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 six months ended June 30, 2009 was $723,000. The fair value of ARO is calculated using significant unobservable inputs (Level 3).

***Note 6. Long-term Debt***

The Company had $592.0 million and $376.4 million in long-term debt outstanding at June 30, 2009 and December 31, 2008, respectively, on its revolving credit facility due April 11, 2011. At the Company s election, the maturity date can be extended for up to two one-year periods. Borrowings under the facility bear interest, payable quarterly, at a rate per annum equal to the London

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Interbank Offered Rate 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. The revolving credit facility has a maximum facility amount of $750.0 million and a borrowing base of $850.0 million, subject to semi-annual re-determination. The commitment level was increased from $672.5 million to $750.0 million on June 25, 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 was 2.60% at June 30, 2009. Amounts outstanding under the revolving credit facility at June 30, 2009 are stated at cost, which approximates fair value.

The Company had $158.0 million of unused commitments under the revolving credit facility at June 30, 2009 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 June 30, 2009.

***Note 7. Commitments and Contingencies***

*Drilling Commitments.* As of June 30, 2009, 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 June 30, 2009 are $19.1 million for the contract expiring in 2011.

*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 first half of 2009 and the year ended December 31, 2008, contributions to the plan were 5% of eligible employees compensation, excluding bonuses.

*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 June 30, 2009 and December 31, 2008, the accrued liability for health and worker s compensation claims was $1.1 million and $0.9 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 June 30, 2009 and December 31, 2008, the Company has provided a reserve of $2.7 million and $1.2 million, respectively, for various matters none of which are believed to be individually significant.

*Environmental Risk.* Due to the nature of the oil and 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 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 $5.4 million for the six months ended June 30, 2009 and $3.9 million for the six months ended June 30, 2008.

*Stock Options*

Effective October 1, 2000, the Company adopted the 2000 Plan and granted options to 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 June 30, 2009, options covering 1,870,463 shares had been exercised.

The Company s stock option activity under the 2000 Plan for the six months ended June 30, 2009 was as follows:

| | Outstanding | | Exercisable | |
|---|---|---|---|---|
| | Number of options | Weighted average exercise price | Number of options | Weighted average exercise price |
| Outstanding December 31, 2008 | 450,200 | $ 1.28 | 450,200 | $ 1.28 |
| Exercised | (7,000) | 0.71 | (7,000) | 0.71 |
| Outstanding June 30, 2009 | 443,200 | 1.29 | 443,200 | 1.29 |

The intrinsic value of a stock option is the amount by which the value of the underlying stock exceeds the exercise price of the option at its exercise date. The total intrinsic value of options exercised during the six months ended June 30, 2009 was approximately $97,000. At June 30, 2009, all options were exercisable and had a weighted average life of 1.3 years with an aggregate intrinsic value of $11.7 million.

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*Restricted Stock*

On October 3, 2005, the Company adopted the 2005 Plan and reserved a maximum of 5,500,000 shares of common stock that may be issued pursuant to the 2005 Plan. As of June 30, 2009, the Company had 3,521,962 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.

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 six months ended June 30, 2009, is presented below:

| | Unvested restricted Shares | Weighted average grant-date fair value |
|---|---|---|
| Unvested restricted shares at December 31, 2008 | 1,110,892 | $ 24.05 |
| Granted | 109,496 | 24.72 |
| Vested | (62,260) | 27.59 |
| Forfeited | (24,004) | 21.70 |
| Outstanding June 30, 2009 | 1,134,124 | 23.97 |

The fair value of the restricted shares that vested during the six months ended June 30, 2009 at their vesting date was $1.5 million. As of June 30, 2009, there was $13.9 million of unrecognized compensation expense related to non-vested restricted shares. The expense is expected to be recognized over a weighted average period of 1.27 years.

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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. The words believe, expect, anticipate, plan, intend, foresee, should, would, could or other similar express intended to identify forward-looking statements, which are generally not historical in nature. These forward-looking statements are based on our current expectations and beliefs concerning future developments and their potential effect on us. While management believes that these forward-looking statements are reasonable as and when made, there can be no assurance that future developments affecting us will be those that we currently anticipate. All comments concerning our expectations for future revenues and operating results are based on our forecasts for our existing operations and do not include the potential impact of any future acquisitions. Our forward-looking statements involve significant risks and uncertainties (some of which are beyond our control) and assumptions that could cause actual results to differ materially from our historical experience and our present expectations or projections. Important factors that could cause actual results to differ materially from those in the forward-looking statements include, but are not limited to, those summarized below:

business strategy;

reserves;

technology;

financial strategy;

oil and natural gas realized prices;

timing and amount of future production of oil and natural gas;

the amount, nature and timing of capital expenditures;

drilling of wells;

competition and government regulations;

marketing of 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.

Other factors that could cause our actual results to differ from our projected results are described in (1) our Annual Report on Form 10-K for the fiscal year ended December 31, 2008, (2) our reports and registration statements filed from time to time with the SEC and (3) 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. We undertake no obligation to publicly update or revise any forward-looking statements after the date they are made, whether as a result of new information, future events or otherwise.

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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, 2008. 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 oil and natural gas exploration, exploitation and production activities in the Rocky Mountain, Mid-Continent and Gulf Coast 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 target large repeatable resource plays where horizontal drilling, advanced fracture stimulation and enhanced recovery technologies provide the means to economically develop and produce oil and natural gas reserves from unconventional formations. We derive the majority of our operating income and cash flow from the sale of 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 oil and natural gas production. In recent months and years, there has been significant volatility in oil and natural gas prices due to a variety of factors we can not control or predict, including political and economic events, weather conditions, and competition from other energy sources. These factors impact supply and demand for oil and natural gas, which affects oil and natural gas prices. In addition, the prices we realize for our oil and natural gas production are affected by location differences in market prices. Oil and natural gas prices have declined dramatically over the past year and have made a material impact on our operating results as we discuss in detail below.

For the first six months of 2009, our oil and natural gas production increased to 6,711 MBoe (37,079 Boe per day), up 19% from the first six months of 2008. The increase in 2009 production was primarily driven by an increase in production from our Arkoma Woodford and Bakken fields. Despite this substantial increase in production, our oil and natural gas revenues for the first six months of 2009 decreased by 54% to $239.0 million due to a 60% decrease in commodity prices compared to the same period in 2008. Our realized price per Boe decreased $55.35 to $36.99 for the six months ended June 30, 2009 compared to the six months ended June 30, 2008. While we experienced decreases in production expense and production tax and other expenses of a combined total of $15.6 million, or 19%, due to a decrease in workover expense and a decrease in production taxes as a result of lower commodity prices, respectively, our decrease in combined per unit cost was $4.16 per Boe, or 29%, as a result of a 796 MBoe increase in sales volumes. For the six months ended June 30, 2009, oil sales volumes were 251 MBbls less than oil production due to temporary storage of barrels in response to low prices and pipeline line fill requirements. Oil sales volumes were 35 MBbls more than production for the same period in 2008 due to the sale of crude oil inventory. Our cash flow from operating activities for the six months ended June 30, 2009, was $82.5 million, a decrease of $215.5 million from $298.0 million provided by our operating activities during the comparable 2008 period. The decrease in operating cash flows was primarily due to decreases in commodity prices. During the six months ended June 30, 2009, we invested $227.4 million (excluding payments to reduce accruals of $71.1 million and including seismic costs) in our capital program concentrating mainly in the Red River units, the Bakken field and the Arkoma Woodford play.

In response to significantly lower oil and natural gas prices during the fourth quarter of 2008 and the first three months of 2009 and the resulting decrease in cash flows, we significantly reduced our capital expenditures budget for 2009 to $275 million. Due to drilling rig commitments and in-progress drilling operations, we knew these expenditures would be heavily weighted toward the first quarter of 2009. Based on increased crude oil prices in the second quarter of 2009 Continental has increased its 2009 capital expenditures budget by 42% from the previously announced budget to $390 million, with the majority of the additional spending directed at drilling operations in the North Dakota Bakken. Even though capital expenditures for the six months ended June 30, 2009 exceeded cash flow from operations, we still expect to manage our capital expenditures for the year to be inline with our cash flows from operations. To the extent commodity price changes cause us to generate insufficient cash flow to finance this budget, we may decrease our actual capital expenditures during 2009 or increase debt.

*How We Evaluate Our Operations*

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

- volumes of oil and natural gas produced,
- 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 June 30, 2009 | Three months ended June 30, 2008 | Six months ended June 30, 2009 | Six months ended June 30, 2008 |
|---|---|---|---|---|
| Average daily production: | | | | |
| Oil (Bbl) | 27,654 | 24,117 | 27,119 | 24,080 |
| Natural gas (Mcf) | 58,156 | 45,035 | 59,760 | 41,098 |
| Oil equivalents (Boe) | 37,347 | 31,623 | 37,079 | 30,930 |
| Average prices: (1) | | | | |
| Oil ($/Bbl) | $ 53.44 | $ 118.28 | $ 44.82 | $ 104.43 |
| Natural gas ($/Mcf) | 2.60 | 8.82 | 2.79 | 8.25 |
| Oil equivalents ($/Boe) | 43.52 | 102.86 | 36.99 | 92.34 |
| Production expense ($/Boe) (1) | 7.14 | 9.32 | 7.19 | 8.83 |
| General and administrative expense ($/Boe) (1) | 2.78 | 3.55 | 3.04 | 3.14 |
| EBITDAX (in thousands) (2) | 106,250 | 244,950 | 163,923 | 426,738 |
| Net income (loss) (in thousands) | 13,508 | 127,307 | (13,105) | 215,278 |
| Diluted net income (loss) per share | 0.08 | 0.75 | (0.08) | 1.27 |

(1) Oil sales volumes were 35 MBbls less than oil production for the three months ended June 30, 2009 and 16 MBbls more than oil production for the three months ended June 30, 2008. For the six months ended June 30, 2009 oil sales volumes were 251 MBbls less than oil production and 35 MBbls more than oil production for the six months ended June 30, 2008. 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 flow 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 June 30, 2009 compared to the three months ended June 30, 2008**

**Results of Operations**

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

| (in thousands, except volume price data) | Three months ended June 30, 2009 | Three months ended June 30, 2008 |
|---|---|---|
| Oil and natural gas sales | $ 146,439 | $ 297,619 |
| Derivatives gain (loss) | 890 | (3,358) |
| Total revenues | 151,761 | 303,434 |
| Operating costs and expenses | 125,580 | 98,205 |
| Other expense | 4,422 | 2,617 |
| Net income, before income taxes | 21,759 | 202,612 |
| Provision for income taxes | 8,251 | 75,305 |
| Net income | $ 13,508 | $ 127,307 |
| Production Volumes: | | |
| Oil (MBbl) | 2,517 | 2,195 |
| Natural gas (MMcf) | 5,293 | 4,098 |
| Oil equivalents (MBoe) | 3,398 | 2,878 |
| Sales Volumes: | | |
| Oil (MBbl) | 2,482 | 2,211 |
| Natural gas (MMcf) | 5,293 | 4,098 |
| Oil equivalents (MBoe) | 3,365 | 2,894 |
| Average Prices: (1) | | |
| Oil ($/Bbl) | $ 53.44 | $ 118.28 |
| Natural gas ($/Mcf) | $ 2.60 | $ 8.82 |

| | | | | |
|---|---|---|---|---|
| Oil equivalents ($/Boe) | $ | 43.52 | $ | 102.86 |

(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 June 30, 2009 Volume | 2009 Percent | 2008 Volume | 2008 Percent | Volume Increase | Percent Increase |
|---|---|---|---|---|---|---|
| Oil (MBbl) | 2,517 | 74% | 2,195 | 76% | 322 | 15% |
| Natural Gas (MMcf) | 5,293 | 26% | 4,098 | 24% | 1,195 | 29% |
| Total (MBoe) | 3,398 | 100% | 2,878 | 100% | 520 | 18% |

| | Three months ended June 30, 2009 MBoe | 2009 Percent | 2008 MBoe | 2008 Percent | Volume increase (decrease) | Percent increase (decrease) |
|---|---|---|---|---|---|---|
| Rocky Mountain | 2,585 | 76% | 2,228 | 77% | 357 | 16% |
| Mid-Continent | 766 | 23% | 595 | 21% | 171 | 29% |
| Gulf Coast | 47 | 1% | 55 | 2% | (8) | (15)% |
| Total (MBoe) | 3,398 | 100% | 2,878 | 100% | 520 | 18% |

Oil production volumes increased 15% during the three months ended June 30, 2009 compared to the three months ended June 30, 2008. Production increases in the Bakken field and the Red River units contributed incremental volumes in 2009 of 371 MBbls in excess of production for the second quarter of 2008. 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, most notably a 34 MBbl decrease in the Rockies Other area. Natural gas volumes increased 1,195 MMcf, or 29%, during the three months ended June 30, 2009 compared to the same period in 2008. The majority of the increase, 1.1 Bcf, was from the Mid-Continent region due to the results of our exploration efforts in the Arkoma Woodford play. The Rocky Mountain region natural gas production was up 125 MMcf for the three months ended June 30, 2009 compared to the same period in 2008 due to additional natural gas being connected and sold in North Dakota.

***Revenues***

*Oil and Natural Gas Sales.* Oil and natural gas sales for the three months ended June 30, 2009 were $146.4 million, a 51% decrease from sales of $297.6 million for the same period in 2008. Our sales volumes increased 471 MBoe or 16% over the same period in 2008 volumes due to the continuing success of our enhanced oil recovery and drilling programs. Our realized price per Boe decreased $59.33 to $43.52 for the three months ended June 30, 2009 from $102.86 for the three months ended June 30, 2008. The differential between NYMEX calendar month average crude oil prices and our realized crude oil price per barrel for the three months ended June 30, 2009 was $6.02 compared to $5.75 for the three months ended June 30, 2008, $8.32 for the first quarter 2009, and $9.50 for the year ended December 31, 2008. Factors contributing to the changing differentials included Canadian oil imports and increases in production in the Rocky Mountain region, coupled with downstream transportation capacity constraints, refinery downtime in the Rocky Mountain region, and seasonal demand fluctuations for gasoline.

*Derivatives.* SFAS No. 133, *Accounting for Derivative Instruments and Hedging Activities* requires recognition of 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 under the provisions of SFAS No. 133. As a result, we marked our derivative instruments to fair value in accordance with the provisions of SFAS No. 133 and recognized the realized and unrealized change in fair value on derivative instruments in the statement of operations under the caption Gain (loss) on mark-to-market derivative instruments.

In July 2007, we entered into fixed-price swap contracts covering 10,000 barrels of oil per day for the period from August 2007 through April 2008 to partially reduce price risk. During each month of the contract, we received a fixed-price of $72.90 per barrel and paid to the counterparties the average of the prompt NYMEX crude oil futures contract settlement prices for such month. These contracts expired in April 2008 and during the three months ended June 30, 2008 we had recognized losses on derivatives of $3.4 million. Currently our crude oil production remains unhedged.

In June 2009, we entered into natural gas fixed price swaps for 600,000 MMBtu per month at an average price of $5.80 per MMBtu for December 2009 and $6.30 per MMBtu for calendar year 2010. We also entered into basis swaps for the same volumes and periods to lock in the difference between NYMEX natural gas prices and Inside FERC Centerpoint Energy East Index at an average differential of ($0.53) per MMBtu for December 2009 and ($0.62) for calendar year 2010. These swaps were put in place to underpin our current and expected level of operations in the Arkoma Woodford play in southeastern Oklahoma by securing a predictable cash flow stream on about a third of our natural gas production for the periods covered. We reported non-cash unrealized mark-to-market gains from our gas derivatives of $890,000 for the three months ended June 30, 2009.

*Oil and Natural Gas Service Operations.* Our oil and natural gas service operations consist primarily of sales of high-pressure air and the treatment and sale of lower quality crude oil, or reclaimed oil. Prices for reclaimed oil sold from our central treating unit were lower

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for the three months ended June 30, 2009 than the comparable 2008 period. The price decreased $56.01 per barrel which decreased reclaimed oil income by $4.5 million contributing to an overall decrease in oil and gas service operations revenue of $4.7 million for the three months ended June 30, 2009. Associated oil and natural gas service operations expenses decreased $3.8 million to $2.7 million during the three months ended June 30, 2009 from $6.5 million during the three months ended June 30, 2008 due mainly to a decrease in the costs of purchasing and treating oil for resale compared to the same period in 2008. We sold high-pressure air from our Red River units to a third party and recorded revenues of $0.4 million for the three months ended June 30, 2009 compared to $0.8 million for the three months ended June 30, 2008.

***Operating Costs and Expenses***

*Production Expense and Production Tax and Other Expenses*. Production expense decreased $3.0 million, or 11%, during the three months ended June 30, 2009 to $24.0 million from $27.0 million during the three months ended June 30, 2008. During the three months ended June 30, 2009, we participated in the completion of 50 gross (14.2 net) wells. Production expense per Boe decreased to $7.14 for the three months ended June 30, 2009 from $9.32 per Boe for the three months ended June 30, 2008 due to a decrease in workover expenses coupled with an increase in sales volumes.

Production tax and other expenses decreased $6.1 million, or 34%, during the three months ended June 30, 2009 compared to the three months ended June 30, 2008 as a result of lower revenues resulting from decreased sales prices partially offset by the expiration of various tax incentives and increases in other charges. 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 $2.3 million and $0.5 million for the three months ended June 30, 2009 and 2008, respectively. Production tax, excluding other charges, as a percentage of oil and natural gas sales was 6.4% for the three months ended June 30, 2009 compared to 5.9% for the three months ended June 30, 2008. 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 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 June 30, | | Percent |
|---|---|---|---|
| **($/Boe)** | **2009** | **2008** | **Decrease** |
| Production expense | $ 7.14 | $ 9.32 | (23%) |
| Production tax and other expenses | 3.46 | 6.12 | (43%) |
| Production expense, production tax and other expenses | $ 10.60 | $ 15.44 | (31%) |

*Exploration Expense*. Exploration expense consists primarily of dry hole costs and exploratory geological and geophysical costs that are expensed as incurred. Exploration expense decreased $4.2 million in the three months ended June 30, 2009 to $1.5 million due primarily to a decrease in seismic expense of $3.3 million to $0.3 million and a decrease in dry hole expense of $1.1 million.

*Depreciation, Depletion, Amortization and Accretion ( DD&A ).* Total DD&A increased $25.1 million in the second quarter of 2009 compared to the second quarter of 2008, primarily due to an increase in oil and natural gas DD&A of $24.9 million as a result of increased production and additional properties with higher cost reserves being added through our drilling program. Additionally, DD&A increased as a result of the decrease in commodity prices used to calculate year end 2008 reserves volumes. Lower prices have the effect of decreasing the economic life of oil and natural gas properties, which lowers future reserve volumes and increases DD&A. The following table shows the components of our DD&A rate per Boe.

| | Three months ended June 30, | |
|---|---|---|
| **($/Boe)** | **2009** | **2008** |
| Oil and natural gas | $ 15.40 | $ 9.33 |
| Other equipment | 0.23 | 0.20 |
| Asset retirement obligation accretion | 0.17 | 0.17 |

| | | |
|---|---|---|
| Depreciation, depletion, amortization and accretion | $ 15.80 | $ 9.70 |

*Property Impairments.* Property impairments, non-producing and developed, increased in the three months ended June 30, 2009 by $20.1 million to $23.3 million compared to $3.2 million during the three months ended June 30, 2008. Impairment of non-producing properties increased $10.5 million during the three months ended June 30, 2009 to $13.2 million compared to $2.7 million for the three months ended June 30, 2008 reflecting higher amortization of leasehold 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.

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Impairment provisions for developed oil and gas properties were approximately $10.1 million for the three months ended June 30, 2009 compared to approximately $0.4 million for the three months ended June 30, 2008, an increase of $9.7 million. We evaluate our developed oil and 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. The majority of the impairment in 2009 reflects uneconomic drilling results in our Mid-Continent region which resulted in impairments of $10.0 million for the three months ended June 30, 2009. The remaining impairment is the result of decreases in reserves and prices.

*General and Administrative Expense.* General and administrative expense decreased $0.9 million to $9.4 million during the three months ended June 30, 2009 from $10.3 million during the comparable period of 2008. General and administrative expense includes non-cash charges for stock-based compensation of $2.7 million and $2.5 million for the three months ended June 30, 2009 and 2008, respectively. General and administrative expense excluding equity compensation decreased $1.1 million for the three months ended June 30, 2009 compared to the three months ended June 30, 2008. The decrease was primarily related to a donation of $1.0 million made in 2008 to Oklahoma State University to support a petroleum engineering program that was not repeated in 2009. On a volumetric basis, general and administrative expense decreased $0.77 to $2.78 per Boe for the three months ended June 30, 2009 compared to $3.55 per Boe for the three months ended June 30, 2008.

*Interest Expense.* Interest expense increased 65%, or $1.9 million, for the three months ended June 30, 2009 compared to the three months ended June 30, 2008, due to higher debt balances. Our average debt balance increased to $612.6 million for the three months ended June 30, 2009 compared to $241.3 million for the three months ended June 30, 2008, but the weighted average interest rate on our revolving credit facility was lower at 2.72% for the three months ended June 30, 2009 compared to 4.40% for the same period in 2008. As described in greater detail below (see Liquidity and Capital Resources) a significant portion of the increased borrowings were used to pay for capital expenditures incurred during the first quarter of 2009 that could not be funded from cash flows from operations due to the significant decrease in commodity prices. At July 31, 2009 our outstanding debt balance was $572.0 million with a weighted average interest rate of 2.57%.

*Income Taxes.* We recorded income tax expense for the three months ended June 30, 2009 of $8.3 million compared to $75.3 million for the three months ended June 30, 2008. We provide taxes at a combined federal and state tax rate of approximately 38% after taking into account permanent taxable differences.

**Six months ended June 30, 2009 compared to the six months ended June 30, 2008**

**Results of Operations**

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

| | Six months ended June 30, | |
|---|---|---|
| **(in thousands, except volume price data)** | **2009** | **2008** |
| Oil and natural gas sales | $ 239,007 | $ 523,044 |
| Derivatives gain (loss) | 890 | (7,966) |
| Total revenues | 248,369 | 531,085 |
| Operating costs and expenses | 260,620 | 184,163 |
| Other expense | 8,862 | 5,729 |
| Net income (loss), before income taxes | (21,113) | 341,193 |
| Provision (benefit) for income taxes | (8,008) | 125,915 |
| Net (loss) income | $ (13,105) | $ 215,278 |
| Production Volumes: | | |
| Oil (MBbl) | 4,909 | 4,383 |
| Natural gas (MMcf) | 10,817 | 7,480 |
| Oil equivalents (MBoe) | 6,711 | 5,629 |
| Sales Volumes: | | |
| Oil (MBbl) | 4,658 | 4,418 |
| Natural gas (MMcf) | 10,817 | 7,480 |
| Oil equivalents (MBoe) | 6,461 | 5,665 |
| Average Prices: (1) | | |

| | | | | |
|---|---|---|---|---|
| Oil ($/Bbl) | $ | 44.82 | $ | 104.43 |
| Natural gas ($/Mcf) | $ | 2.79 | $ | 8.25 |
| Oil equivalents ($/Boe) | $ | 36.99 | $ | 92.34 |

(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.

| | Six months ended June 30, 2009 Volume | 2009 Percent | 2008 Volume | 2008 Percent | Volume increase | Percent increase |
|---|---|---|---|---|---|---|
| Oil (MBbl) | 4,909 | 73% | 4,383 | 78% | 526 | 12% |
| Natural Gas (MMcf) | 10,817 | 27% | 7,480 | 22% | 3,337 | 45% |
| Total (MBoe) | 6,711 | 100% | 5,629 | 100% | 1,082 | 19% |

| | Six months ended June 30, 2009 MBoe | 2009 Percent | 2008 MBoe | 2008 Percent | Volume increase (decrease) | Percent increase (decrease) |
|---|---|---|---|---|---|---|
| Rocky Mountain | 5,027 | 75% | 4,402 | 78% | 625 | 14% |
| Mid-Continent | 1,580 | 24% | 1,117 | 20% | 463 | 41% |
| Gulf Coast | 104 | 1% | 110 | 2% | (6) | (5)% |
| Total (MBoe) | 6,711 | 100% | 5,629 | 100% | 1,082 | 19% |

Oil production volumes increased 12% during the six months ended June 30, 2009 compared to the six months ended June 30, 2008. Production increases in the Bakken field area contributed incremental volumes in excess of production for the same period in 2008 of 568 MBbls. Favorable results from drilling have been the primary contributors to production growth. This increase was partially offset by decreases in other areas, most notably a 39 MBbl decrease in the Rockies Other area. Natural gas volumes increased 3,337 MMcf, or 45%, during the three months ended June 30, 2009 compared to the same period in 2008. The majority of the increase, 2.8 Bcf, was from the Mid-Continent region due to the results of our exploration efforts in the Arkoma Woodford play. The Rocky Mountain region natural gas production was up 494 MMcf for the six months ended June 30, 2009 compared to the same period in 2008 due to additional natural gas being connected and sold in North Dakota.

***Revenues***

*Oil and Natural Gas Sales.* Oil and natural gas sales for the six months ended June 30, 2009 were $239.0 million, a 54% decrease from sales of $523.0 million for the same period in 2008. Our sales volumes increased 796 MBoe or 14% over the same period in 2008 volumes due to the continuing success of our enhanced oil recovery and drilling programs. Our realized price per Boe decreased $55.35 to $36.99 for the six months ended June 30, 2009 from $92.34 for the six months ended June 30, 2008. The differential between NYMEX calendar month average crude oil prices and our realized crude oil price per barrel for the six months ended June 30, 2009 was $7.08 compared to $6.58 for the six months ended June 30, 2008 and $9.50 for the year ended December 31, 2008. Factors contributing to the changing differentials included Canadian oil imports and increases in production in the Rocky Mountain region, coupled with downstream transportation capacity constraints, refinery downtime in the Rocky Mountain region, and reduced seasonal demand for gasoline.

*Derivatives.* SFAS No. 133, *Accounting for Derivative Instruments and Hedging Activities* requires recognition of 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 under the provisions of SFAS No. 133.