ENCORE ACQUISITION CO
Form 10-Q
August 09, 2007

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**UNITED STATES**
**SECURITIES AND EXCHANGE COMMISSION**
**Washington, D.C. 20549**
**FORM 10-Q**

(Mark One)

þ **QUARTERLY REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**

**For the quarterly period ended June 30, 2007**

**or**

o **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: 001-16295**

**ENCORE ACQUISITION COMPANY**

(Exact name of registrant as specified in its charter)

| | |
|---|---|
| **Delaware** | **75-2759650** |
| (State or other jurisdiction of incorporation or organization) | (I.R.S. Employer Identification No.) |
| **777 Main Street, Suite 1400, Fort Worth, Texas** | **76102** |
| (Address of principal executive offices) | (Zip Code) |

**(817) 877-9955**

(Registrant s telephone number, including area code)

**Not applicable**

(Former name, former address and former fiscal year, if changed since last report)

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days. Yes þ No o

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, or a non-accelerated filer. See definition of accelerated filer and large accelerated filer in Rule 12b-2 of the Exchange Act. (Check one):

Large accelerated filer þ Accelerated filer o Non-accelerated filer o

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Exchange Act). Yes o No þ

| | |
|---|---|
| Number of shares of common stock, $0.01 par value, outstanding as of August 1, 2007 | 53,186,851 |

**ENCORE ACQUISITION COMPANY**
**INDEX**



**CAUTIONARY STATEMENT REGARDING FORWARD-LOOKING INFORMATION**

Certain information included in this Quarterly Report on Form 10-Q (the Report ) and other materials filed with the Securities and Exchange Commission ( SEC ), or in other written or oral statements made or to be made by us, other than statements of historical fact, are forward-looking statements as defined by the safe harbor provisions of the Private Securities Litigation Reform Act of 1995. These forward-looking statements give our current expectations or forecasts of future events. You can identify our forward-looking statements by the fact that they do not relate strictly to historical or current facts. These statements may include words such as anticipate, estimate, expect, project, int plan, believe, should, and other words and terms of similar meaning. Our actual results may differ significantly from the results discussed in the forward-looking statements. Such statements involve risks and uncertainties, including, but not limited to, the matters discussed in Item 1A. Risk Factors in our Annual Report on Form 10-K for the year ended December 31, 2006 and in our other filings with the SEC. If one or more of these risks or uncertainties materialize, or should underlying assumptions prove incorrect, actual outcomes may vary materially from those indicated. You should not place undue reliance on forward-looking statements. Each forward-looking statement speaks only as of the date of the particular statement. We undertake no responsibility to update forward-looking statements for changes related to these or any other factors that may occur subsequent to this filing for any reason.

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## ENCORE ACQUISITION COMPANY
## GLOSSARY OF CERTAIN TERMS

The following are abbreviations and definitions of certain terms used in this Report:

*Bbl.* One stock tank barrel, or 42 U.S. gallons liquid volume, used in reference to oil or other liquid hydrocarbons.

*Bbl/D*. One Bbl per day.

*BOE.* One barrel of oil equivalent, calculated by converting natural gas to oil equivalent barrels at a ratio of six Mcf of natural gas to one Bbl of oil.

*BOE/D*. One BOE per day.

*Encore or the Company.* Encore Acquisition Company, a Delaware corporation, together with its subsidiaries.

*Gross Wells.* The total number of wells in which we own a working interest.

*High-Pressure Air Injection (  HPAI  ).* HPAI involves utilizing compressors to force air under high pressure into previously produced oil and natural gas formations in order to displace remaining resident hydrocarbons and force them under pressure to a common lifting point for production.

*LIBOR.* London Interbank Offered Rate.

*MBbls.* One thousand Bbls.

*Mcf.* One thousand cubic feet of natural gas.

*Mcf/D.* One Mcf per day.

*Net Wells.* Gross wells multiplied by the percentage of the working interest owned by us.

*NYMEX.* New York Mercantile Exchange.

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

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

See the Company  s Annual Report on Form 10-K for the year ended December 31, 2006 for definitions of additional terms that may be used in this Report.

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## PART I. FINANCIAL INFORMATION

### Item 1. Financial Statements

### ENCORE ACQUISITION COMPANY
### CONSOLIDATED BALANCE SHEETS
(in thousands, except share and per share amounts)

| | June 30, 2007 (unaudited) | December 31, 2006 |
|---|---|---|
| **ASSETS** | | |
| Current assets: | | |
| Cash and cash equivalents | $ 4,938 | $ 763 |
| Accounts receivable | 114,770 | 81,470 |
| Inventory | 21,235 | 18,170 |
| Derivatives | 19,552 | 17,349 |
| Deferred taxes | 18,713 | 24,978 |
| Prepaid expenses | 5,272 | 2,988 |
| Assets held for sale | 3,205 | |
| Total current assets | 187,685 | 145,718 |
| Properties and equipment, at cost successful efforts method: | | |
| Proved properties, including wells and related equipment | 2,636,785 | 2,033,914 |
| Unproved properties | 51,482 | 47,548 |
| Accumulated depletion, depreciation, and amortization | (394,367) | (364,780) |
| | 2,293,900 | 1,716,682 |
| Other property and equipment | 19,772 | 18,231 |
| Accumulated depreciation | (9,065) | (7,791) |
| | 10,707 | 10,440 |
| Goodwill | 60,606 | 60,606 |
| Derivatives | 29,078 | 40,715 |
| Long-term receivables | 44,748 | 19,642 |
| Other | 34,672 | 13,097 |
| Total assets | $ 2,661,396 | $ 2,006,900 |
| **LIABILITIES AND STOCKHOLDERS EQUITY** | | |
| Current liabilities: | | |
| Accounts payable | $ 30,812 | $ 18,204 |
| Accrued liabilities: | | |
| Lease operations expense | 12,675 | 8,582 |
| Development capital | 36,833 | 44,492 |

| | | |
|---|---|---|
| Interest | 14,435 | 11,273 |
| Production, ad valorem, and severance taxes | 19,400 | 10,915 |
| Oil purchases | 6,493 | 11,191 |
| Derivatives | 53,220 | 60,448 |
| Other | 24,142 | 21,358 |
| Total current liabilities | 198,010 | 186,463 |
| Derivatives | 28,741 | 38,688 |
| Future abandonment cost | 27,758 | 19,205 |
| Deferred taxes | 278,823 | 282,825 |
| Long-term debt | 1,300,962 | 661,696 |
| Other | 1,290 | 1,158 |
| Total liabilities | 1,835,584 | 1,190,035 |
| Commitments and contingencies (see Note 14) | | |
| Stockholders equity: | | |
| Preferred stock, $.01 par value, 5,000,000 shares authorized, none issued and outstanding | | |
| Common stock, $.01 par value, 144,000,000 shares authorized, 53,186,851 and 53,028,866 issued and outstanding, respectively | 532 | 531 |
| Additional paid-in capital | 464,246 | 457,201 |
| Treasury stock, at cost, of 21,288 and 17,809 shares, respectively | (546) | (457) |
| Retained earnings | 380,353 | 394,917 |
| Accumulated other comprehensive loss | (18,773) | (35,327) |
| Total stockholders equity | 825,812 | 816,865 |
| Total liabilities and stockholders equity | $ 2,661,396 | $ 2,006,900 |

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

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**ENCORE ACQUISITION COMPANY**
**CONSOLIDATED STATEMENTS OF OPERATIONS**
(in thousands, except per share amounts)
(unaudited)

| | Three months ended June 30, | | Six months ended June 30, | |
|---|---|---|---|---|
| | 2007 | 2006 | 2007 | 2006 |
| Revenues: | | | | |
| Oil | $ 135,596 | $ 92,434 | $ 218,219 | $ 168,549 |
| Natural gas | 45,131 | 39,343 | 78,109 | 76,873 |
| Marketing | 8,916 | 25,716 | 23,857 | 60,032 |
| Total revenues | 189,643 | 157,493 | 320,185 | 305,454 |
| Expenses: | | | | |
| Production: | | | | |
| Lease operations | 37,552 | 23,118 | 68,072 | 45,854 |
| Production, ad valorem, and severance taxes | 19,232 | 12,580 | 31,747 | 24,822 |
| Depletion, depreciation, and amortization | 52,318 | 27,988 | 87,346 | 55,008 |
| Exploration | 3,415 | 4,016 | 14,936 | 6,025 |
| General and administrative | 6,188 | 5,421 | 13,548 | 11,949 |
| Marketing | 8,507 | 24,914 | 23,518 | 57,660 |
| Derivative fair value loss | 6,766 | 10,794 | 52,380 | 13,100 |
| Other operating | 4,751 | 1,068 | 7,316 | 2,596 |
| Total expenses | 138,729 | 109,899 | 298,863 | 217,014 |
| Operating income | 50,914 | 47,594 | 21,322 | 88,440 |
| Other income (expenses): | | | | |
| Interest | (27,820) | (10,718) | (44,107) | (22,505) |
| Other | 601 | 428 | 1,032 | 549 |
| Total other income (expenses) | (27,219) | (10,290) | (43,075) | (21,956) |
| Income (loss) before income taxes | 23,695 | 37,304 | (21,753) | 66,484 |
| Income tax benefit (provision) | (8,524) | (15,069) | 7,496 | (26,313) |
| Net income (loss) | $ 15,171 | $ 22,235 | $ (14,257) | $ 40,171 |
| Net income (loss) per common share: | | | | |
| Basic | $ 0.29 | $ 0.42 | $ (0.27) | $ 0.79 |
| Diluted | $ 0.28 | $ 0.42 | $ (0.27) | $ 0.78 |

| | | | | |
|---|---|---|---|---|
| Weighted average common shares outstanding: | | | | |
| Basic | 53,143 | 52,631 | 53,111 | 50,724 |
| Diluted | 54,020 | 53,532 | 53,111 | 51,663 |

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

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**ENCORE ACQUISITION COMPANY**
**CONSOLIDATED STATEMENT OF STOCKHOLDERS EQUITY**
(in thousands)
(unaudited)

| | Issued Shares of Common Stock | Common Stock | Additional Paid-in Capital | Shares of Treasury Stock | Treasury Stock | Retained Earnings | Accumulated Other Comprehensive Loss | Total Stockholders Equity |
|---|---|---|---|---|---|---|---|---|
| **Balance at December 31, 2006** | 53,047 | $ 531 | $ 457,201 | (18) | $ (457) | $ 394,917 | $ (35,327) | $ 816,865 |
| Exercise of stock options and vesting of restricted stock | 179 | 1 | 1,042 | | | | | 1,043 |
| Purchase of treasury stock | | | | (21) | (546) | | | (546) |
| Cancellation of treasury stock | (18) | | (150) | 18 | 457 | (307) | | |
| Non-cash stock-based compensation | | | 6,153 | | | | | 6,153 |
| Components of comprehensive income: | | | | | | | | |
| Net loss | | | | | | (14,257) | | (14,257) |
| Amortization of deferred hedge losses, net of tax of $10,240 | | | | | | | 16,554 | 16,554 |
| Total comprehensive income | | | | | | | | 2,297 |
| **Balance at June 30, 2007** | 53,208 | $ 532 | $ 464,246 | (21) | $ (546) | $ 380,353 | $ (18,773) | $ 825,812 |

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

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**ENCORE ACQUISITION COMPANY**
**CONSOLIDATED STATEMENTS OF CASH FLOWS**
(in thousands)
(unaudited)

| | Six months ended June 30, 2007 | Six months ended June 30, 2006 |
|---|---|---|
| Cash flows from operating activities: | | |
| Net income (loss) | $ (14,257) | $ 40,171 |
| Adjustments to reconcile net income (loss) to net cash provided by operating activities: | | |
| Depletion, depreciation, and amortization | 87,346 | 55,008 |
| Non-cash exploration expense | 13,870 | 2,580 |
| Deferred taxes | (7,745) | 25,211 |
| Non-cash stock-based compensation expense | 5,480 | 4,853 |
| Non-cash derivative | 65,038 | 19,099 |
| Loss on disposition of assets | 2,282 | 472 |
| Other | 2,589 | 2,954 |
| Changes in operating assets and liabilities, net of effects from acquisitions: | | |
| Accounts receivable | (42,735) | 2,205 |
| Current derivatives | (15,303) | |
| Other current assets | (8,554) | (5,464) |
| Long-term derivatives | (19,828) | (2,840) |
| Other assets | (2,200) | (2,019) |
| Accounts payable | 4,468 | (1,428) |
| Other current liabilities | 11,127 | (2,067) |
| Other noncurrent liabilities | (253) | (7,259) |
| Net cash provided by operating activities | 81,325 | 131,476 |
| Cash flows from investing activities: | | |
| Proceeds from disposition of assets | 291,454 | 536 |
| Purchases of other property and equipment | (1,614) | (2,515) |
| Acquisition of oil and natural gas properties | (779,576) | (15,917) |
| Development of oil and natural gas properties | (187,227) | (146,959) |
| Net advances to working interest partners | (24,158) | (1,178) |
| Other | | (342) |
| Net cash used in investing activities | (701,121) | (166,375) |
| Cash flows from financing activities: | | |
| Proceeds from issuance of common stock, net of issuance costs | | 126,890 |
| Exercise of stock options and vesting of restricted stock, net of treasury stock purchases | 497 | 2,822 |
| Proceeds from long-term debt | 1,131,500 | 104,000 |
| Payments on long-term debt | (492,500) | (184,000) |

| | | |
|---|---|---|
| Debt issuance costs | (11,481) | (200) |
| Change in cash overdrafts | 8,140 | (15,606) |
| Payment of deferred hedge premiums | (12,185) | |
| Other | | 2 |
| Net cash provided by financing activities | 623,971 | 33,908 |
| Increase (decrease) in cash and cash equivalents | 4,175 | (991) |
| Cash and cash equivalents, beginning of period | 763 | 1,654 |
| Cash and cash equivalents, end of period | $ 4,938 | $ 663 |

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

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**ENCORE ACQUISITION COMPANY**
**NOTES TO CONSOLIDATED FINANCIAL STATEMENTS**
(unaudited)

**Note 1. About Encore**

Encore is engaged in the acquisition and development of oil and natural gas reserves from onshore fields in the United States. Since 1998, the Company has acquired producing properties with proven reserves and leasehold acreage and grown the production and proven reserves by drilling, exploring, reengineering or expanding existing waterflood projects, and applying tertiary recovery techniques. Encore s properties and oil and natural gas reserves are located in four core areas: the Cedar Creek Anticline ( CCA ) in the Williston Basin of Montana and North Dakota; the Permian Basin of West Texas and southeastern New Mexico; the Rockies, which includes non-CCA assets in the Williston, Big Horn, and Powder River Basins of Wyoming, Montana, and North Dakota and the Paradox Basin of southeastern Utah; and the Mid-Continent area, which includes the Arkoma and Anadarko Basins of Oklahoma, the North Louisiana Salt Basin, the East Texas Basin, and the Barnett Shale of northern Texas.

**Note 2. Basis of Presentation**

The Company s consolidated financial statements include the accounts of wholly-owned and majority-owned subsidiaries and a variable interest entity for which the Company is the primary beneficiary. All material intercompany balances and transactions have been eliminated in consolidation.

In the opinion of management, the accompanying unaudited consolidated financial statements of Encore include all adjustments necessary to present fairly, in all material respects, its financial position as of June 30, 2007, results of operations for the three and six months ended June 30, 2007 and 2006, and cash flows for the six months ended June 30, 2007 and 2006. All adjustments are of a normal recurring nature. These interim results are not necessarily indicative of results for an entire year.

Certain amounts and disclosures have been condensed or omitted from these consolidated financial statements pursuant to the rules and regulations of the SEC. Therefore, these consolidated financial statements should be read in conjunction with the consolidated financial statements and related notes thereto included in the Company s 2006 Annual Report on Form 10-K.

***Variable Interest Entity***

On April 11, 2007, the Company completed the purchase of certain oil and natural gas properties and related assets in the Williston Basin of Montana and North Dakota from certain subsidiaries of Anadarko Petroleum Corporation ( Anadarko ). Prior to closing, Encore assigned all of its rights and duties under the purchase and sale agreement to Encore Operating, L.P., a Texas limited partnership and indirect wholly-owned guarantor subsidiary of Encore, which further assigned all of its rights and duties under the purchase and sale agreement to Encore Exchange, LLC, a Delaware limited liability company unaffiliated with Encore or Encore Operating, L.P. ( Encore Exchange ).

The Williston Basin acquisition was structured to qualify as the first step of a reverse like-kind exchange under Section 1031 of the Internal Revenue Code of 1986, as amended, and I.R.S. Revenue Procedure 2000-37. The Williston Basin assets were acquired by Encore Exchange as an exchange accommodation titleholder . Encore Exchange held the assets pursuant to a qualified exchange accommodation agreement until the second step of the like-kind exchange was completed. During the period the assets were held by Encore Exchange, Encore Operating, L.P. operated the Williston Basin assets pursuant to a management agreement with Encore Exchange. The second step of the like-kind exchange was completed in July 2007 upon the completion of the disposition of certain of Encore s Mid-Continent properties. See Note 3. Acquisitions and Dispositions for additional discussion of the disposition of the Mid-Continent properties.

In connection with the like-kind exchange described above, Encore (through Encore Operating, L.P.) loaned an amount equal to the purchase price to Encore Exchange. Based on the provisions of Financial Accounting Standards Board ( FASB ) Interpretation No. 46(R), *Consolidation of Variable Interest Entities* , the Company determined that Encore Exchange is a variable interest entity for which Encore is the primary beneficiary. Accordingly, Encore Exchange has been consolidated with Encore since April 11, 2007. As of June 30, 2007, Encore Exchange had total assets of approximately $5.4 million. Subsequent to June 30, 2007, these assets were sold and the like-kind exchange completed. Encore Exchange is currently in the process of being dissolved.

***Reclassifications***

Certain amounts in prior periods have been reclassified to conform to the current period presentation. Specifically, the

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**ENCORE ACQUISITION COMPANY**
**NOTES TO CONSOLIDATED FINANCIAL STATEMENTS Continued**
(unaudited)

Company reclassified the net gain/loss from the purchases and sales of third-party oil volumes from Oil revenues to Marketing revenues and Marketing expense and reclassified the related marketing transportation costs from Other operating expense to Marketing expense in the accompanying Consolidated Statements of Operations. These are changes in presentation only and do not affect previously reported net income or earnings per share for either period. The following table details the affected line items from the accompanying Consolidated Statements of Operations for the three and six months ended June 30, 2006:

| | Three months ended June 30, 2006 | Six months ended June 30, 2006 |
|---|---|---|
| | (in thousands) | |
| **As Reported:** | | |
| Oil revenues | $94,128 | $172,814 |
| Marketing revenues | $ | $ |
| Marketing expenses | $ | $ |
| Other operating expenses | $ 1,960 | $ 4,489 |
| **As Reclassified:** | | |
| Oil revenues | $92,434 | $168,549 |
| Marketing revenues | $25,716 | $ 60,032 |
| Marketing expenses | $24,914 | $ 57,660 |
| Other operating expenses | $ 1,068 | $ 2,596 |

***New Accounting Pronouncements***

*Statement of Financial Accounting Standards ( SFAS ) No. 157, Fair Value Measurements ( SFAS 157 )*

In September 2006, the FASB issued SFAS 157. SFAS 157 standardizes the definition of fair value, establishes a framework for measuring fair value in generally accepted accounting principles and expands disclosures related to the use of fair value measures in financial statements. SFAS 157 applies whenever other standards require (or permit) assets or liabilities to be measured at fair value but does not expand the use of fair value measurements. SFAS 157 is effective for financial statements issued for fiscal years beginning after November 15, 2007, and interim periods within those fiscal years. Encore does not expect the implementation of SFAS 157 to have a material impact on its results of operations or financial condition.

*SFAS No. 159, The Fair Value Option for Financial Assets and Financial Liabilities including an amendment of FASB Statement No. 115 ( SFAS 159 )*

In February 2007, the FASB issued SFAS 159. SFAS 159 permits entities to measure many financial instruments and certain other assets and liabilities at fair value on an instrument-by-instrument basis. This statement allows entities to measure eligible items at fair value at specified election dates, with resulting changes in fair value reported in earnings. SFAS 159 is effective as of the beginning of an entity s first fiscal year that begins after November 15, 2007. Encore does not expect the implementation of SFAS 159 to have a material impact on its results of operations or financial condition.

*FASB Staff Position ( FSP ) on FASB Interpretation ( FIN ) 39-1, Amendment of FASB Interpretation No. 39 ( FSP FIN 39-1 )*

In April 2007, the FASB issued FSP FIN 39-1. FSP FIN 39-1 amends FIN 39, *Offsetting of Amounts Related to Certain Contracts* ( FIN 39 ), to permit a reporting entity that is party to a master netting arrangement to offset the fair value amounts recognized for the right to reclaim cash collateral (a receivable) or the obligation to return cash collateral (a payable) against fair value amounts recognized for derivative instruments that have been offset under the same master netting arrangement in accordance with FIN 39. FSP FIN 39-1 is effective for fiscal years beginning after

November 15, 2007. Encore does not expect the implementation of FSP FIN 39-1 to have a material impact on its results of operations or financial condition.

*FSP FIN 48-1, Definition of Settlement in FASB Interpretation No. 48 ( FSP FIN 48-1 )*

In May 2007, the FASB issued FSP FIN 48-1, which amends FIN No. 48, *Accounting for Uncertainty in Income Taxes an Interpretation of FASB Statement No. 109* ( FIN 48 ), to provide guidance on how an entity should determine whether a tax

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**ENCORE ACQUISITION COMPANY**
**NOTES TO CONSOLIDATED FINANCIAL STATEMENTS Continued**
(unaudited)

position is effectively settled for the purpose of recognizing previously unrecognized tax benefits. FSP FIN 48-1 clarifies that a tax position is effectively settled for the purpose of recognizing previously unrecognized tax benefits if the taxing authority has completed all of its required or expected examination procedures, the enterprise does not intend to appeal or litigate any aspect of the tax position, and it is considered remote that the taxing authority would reexamine the tax position. This guidance is effective upon initial adoption of FIN 48, which was adopted by Encore on January 1, 2007. Encore retrospectively adopted the provisions of FSP FIN 48-1 effective January 1, 2007, which did not have an impact on its results of operations or financial condition.

**Note 3. Acquisitions and Dispositions**

***Acquisitions***

On January 23, 2007, the Company entered into a purchase and sale agreement with certain subsidiaries of Anadarko to acquire oil and natural gas properties and related assets in the Williston Basin of Montana and North Dakota. The closing of the Williston Basin acquisition occurred on April 11, 2007 after which time the operations have been included with those of the Company.

The total purchase price for the Williston Basin assets was approximately $393.7 million, including transaction costs of $1.2 million. Based on currently available information, the calculation of the total purchase price and the estimated allocation to the fair value of the Williston Basin assets acquired and liabilities assumed from Anadarko are as follows as of June 30, 2007 (in thousands):

| | |
|---|---|
| **Calculation of total purchase price:** | |
| Cash paid to Anadarko | $ 392,467 |
| Estimated transaction costs | 1,200 |
| Total purchase price | $ 393,667 |
| **Allocation of purchase price to the fair value of net assets acquired:** | |
| Proved properties, including wells and related equipment | $ 379,956 |
| Unproved properties | 16,134 |
| Other | 4,178 |
| Total assets acquired | 400,268 |
| Current liabilities | (3,095) |
| Future abandonment cost | (3,506) |
| Total liabilities assumed | (6,601) |
| Fair value of net assets acquired | $ 393,667 |

At June 30, 2007, the Company was awaiting final post close on the Williston Basin acquisition, which will contain certain customary purchase price adjustments.

On January 16, 2007, the Company entered into a purchase and sale agreement with certain subsidiaries of Anadarko to acquire oil and natural gas properties and related assets in the Big Horn Basin of Wyoming and Montana, which included oil and natural gas properties and related assets in or near the Elk Basin field in Park County, Wyoming and Carbon County, Montana and oil and natural gas properties and related assets in the Gooseberry field in Park County, Wyoming. The closing of the Big Horn Basin acquisition occurred on March 7, 2007 after which time the operations have been included with those of the Company. Prior to closing, Encore assigned the rights and duties under the purchase and sale agreement relating to the Elk Basin assets to Encore Energy Partners Operating LLC ( EEPO ), a Delaware limited liability company and indirect wholly-owned non-guarantor subsidiary of Encore, and the rights and duties under the purchase and sale agreement relating to the Gooseberry assets to Encore Operating, L.P. At closing, EEPO paid the sellers approximately $328.4 million for the Elk Basin assets, and Encore Operating, L.P. paid the sellers approximately $63.7 million for the Gooseberry assets.

**ENCORE ACQUISITION COMPANY**
**NOTES TO CONSOLIDATED FINANCIAL STATEMENTS Continued**
(unaudited)

The total purchase price for the Big Horn Basin assets was approximately $393.3 million, including transaction costs of approximately $1.2 million. Based on currently available information, the calculation of the total purchase price and the estimated allocation to the fair value of the Big Horn Basin assets acquired and liabilities assumed from Anadarko are as follows as of June 30, 2007 (in thousands):

| | |
|---|---|
| **Calculation of total purchase price:** | |
| Cash paid to Anadarko | $ 392,085 |
| Estimated transaction costs | 1,200 |
| Total purchase price | $ 393,285 |
| **Allocation of purchase price to the fair value of net assets acquired:** | |
| Proved properties, including wells and related equipment | $ 392,375 |
| Intangibles | 7,656 |
| Other | 2,524 |
| Total assets acquired | 402,555 |
| Current liabilities | (2,297) |
| Future abandonment cost | (6,973) |
| Total liabilities assumed | (9,270) |
| Fair value of net assets acquired | $ 393,285 |

At June 30, 2007, the Company was awaiting final post close on the Big Horn Basin acquisition, which will contain certain customary purchase price adjustments. The properties and equipment amount in the Big Horn Basin purchase price allocation includes the fair value of proved leasehold costs, lease and well equipment (including flue gas reinjection facilities used to maintain reservoir pressure by compressing and reinjecting the natural gas produced), and an oil pipeline and natural gas pipeline used primarily to transport production from the acquired fields. NGLs are produced as a byproduct of the flue gas tertiary recovery project and are sold at market prices. The revenues generated by these hydrocarbon liquids are included in Oil revenues in the accompanying Consolidated Statements of Operations. Third party revenues and expenses related to the pipelines are included in Marketing revenues and Marketing expense , respectively, in the accompanying Consolidated Statements of Operations.

Encore financed the Big Horn Basin and Williston Basin acquisitions through borrowings under its revolving credit facilities. The operating results related to the Big Horn Basin and Williston Basin assets are included in Encore s operating results from the date of closing forward. As of December 31, 2006, estimated total proved reserves associated with the Big Horn Basin and Williston Basin acquisitions were 38,934 MBOE, 92 percent of which were oil and 90 percent of which were proved developed.

See Note 8. Debt for additional discussion of the Company s revolving credit facilities. See Note 13. Financial Statements of Subsidiary Guarantors below for a discussion of the Company s guarantor and non-guarantor subsidiaries.

***Dispositions***

On June 29, 2007, the Company completed the sale of certain oil and natural gas properties in the Mid-Continent for net proceeds of approximately $293.6 million and recorded a loss on sale of $2.3 million. The disposed properties included certain properties in the Anadarko and Arkoma fields. The Company retained a material oil and natural gas interest in the Anadarko and Arkoma fields and remains active in those areas. Subsequent to June 30, 2007, additional Mid-Continent properties that were subject to exercises of preferential rights were sold for net cash proceeds of $5.5 million. Assets held for sale related to these properties were $3.2 million as of June 30, 2007. Proceeds from the Mid-Continent disposition were used to reduce outstanding borrowings under the Company s revolving credit facilities. As of December 31, 2006, estimated total proved reserves associated with the Mid-Continent disposition were 17,416 MBOE, 92 percent of which were natural gas and 75 percent of which were proved developed.

***Pro Forma***

The following unaudited pro forma combined condensed financial data for the three and six months ended June 30, 2007 and 2006 was derived from the historical financial statements of Encore and from the accounting records of Anadarko to give

**ENCORE ACQUISITION COMPANY**
**NOTES TO CONSOLIDATED FINANCIAL STATEMENTS Continued**
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effect to the Big Horn Basin and Williston Basin asset acquisitions and the Mid-Continent disposition as if they had occurred on January 1, 2006. The unaudited pro forma combined condensed financial information has been included for comparative purposes only and is not necessarily indicative of the results that might have occurred had the Big Horn and Williston acquisitions and the Mid-Continent disposition taken place as of the dates indicated and are not intended to be a projection of future results.

| | Three months ended June 30, | | Six months ended June 30, | |
|---|---|---|---|---|
| | 2007 | 2006 | 2007 | 2006 |
| | (in thousands, except per share amounts) | | | |
| Pro forma total revenues | $ 172,186 | $ 198,204 | $ 327,763 | $ 376,068 |
| Pro forma net income (loss) | $ 15,079 | $ 24,484 | $ (10,824) | $ 42,447 |
| Pro forma net income (loss) per common share: | | | | |
| Basic | $ 0.28 | $ 0.47 | $ (0.20) | $ 0.84 |
| Diluted | $ 0.28 | $ 0.46 | $ (0.20) | $ 0.82 |

**Note 4. Inventory**

Inventory is comprised principally of materials and supplies and oil in pipelines, which are stated at the lower of cost (determined on an average basis) or market. Oil produced at the lease which resides unsold in pipelines is carried at an amount equal to its operating costs to produce. Oil in pipelines purchased from third parties is carried at average purchase price. The Company s inventory consisted of the following as of the dates indicated:

| | June 30, 2007 | December 31, 2006 |
|---|---|---|
| | (in thousands) | |
| Materials and supplies | $ 12,738 | $ 11,784 |
| Oil in pipelines | 8,497 | 6,386 |
| Total inventory | $ 21,235 | $ 18,170 |

**Note 5. Proved Properties**

Amounts shown in the accompanying Consolidated Balance Sheets as Proved properties include leasehold costs and wells and related equipment, both completed and in process, and consisted of the following as of the dates indicated:

| | June 30, 2007 | December 31, 2006 |
|---|---|---|
| | (in thousands) | |
| Proved leasehold costs | $ 1,298,310 | $ 796,932 |
| Wells and related equipment Completed | 1,305,869 | 1,200,938 |
| Wells and related equipment In process | 32,606 | 36,044 |

| | | |
|---|---|---|
| Total proved properties | $ 2,636,785 | $ 2,033,914 |

**Note 6. Derivative Financial Instruments**

The Company had $50.4 million of deferred premiums payable recorded at June 30, 2007, of which $22.8 million is considered long-term and is recorded in Derivatives in the non-current liabilities section of the accompanying Consolidated Balance Sheet and $27.6 million is considered current and is recorded in Derivatives in the current liabilities section of the accompanying Consolidated Balance Sheet. The premiums relate to various oil and natural gas floor contracts and are payable on a monthly basis from July 2007 to January 2010. The Company recorded these amounts at their net present value at the time the contract was entered into and accretes that value up to the eventual settlement price by recording interest expense each period.

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## NOTES TO CONSOLIDATED FINANCIAL STATEMENTS Continued
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***Commodity Contracts Mark-to-Market Accounting: Previously designated as hedges***

Prior to July 2006, the Company used hedge accounting for certain of its derivative contracts, whereby the effective portion of changes in the fair value of the contract was deferred in accumulated other comprehensive loss ( AOCL ) included in stockholders equity in the accompanying Consolidated Balance Sheets rather than recognized in earnings. In the third quarter of 2006, the Company elected to discontinue hedge accounting prospectively for all remaining commodity derivatives which were previously accounted for as hedges. While this change has no effect on cash flows, results of operations are affected by mark-to-market gains and losses, which fluctuate with the swings in oil and natural gas prices. The deferred loss in AOCL at the time of dedesignation is being amortized to oil and natural gas revenues over the original term of the contracts. The amortization of these amounts is included in oil and natural gas revenues with the revenues from the hedged production. All mark-to-market gains and losses from July 2006 forward are recognized in earnings through Derivative fair value loss in the accompanying Consolidated Statements of Operations rather than deferring such amounts in AOCL.

The following tables summarize the Company s open commodity derivative instruments as of June 30, 2007:

*Oil Derivative Instruments*

| Period | Daily Floor Volume (Bbl) | Average Floor Price (per Bbl) | Daily Short Floor Volume (Bbl) | Average Short Floor Price (per Bbl) | Daily Swap Volume (Bbl) | Average Swap Price (per Bbl) | Asset (Liability) Fair Market Value (in thousands) |
|---|---|---|---|---|---|---|---|
| July Dec. 2007 | 14,500 | $ 56.72 | | $ | 3,000 | $ 36.75 | $ (17,410) |
| Jan. June 2008 | 18,500 | 62.84 | (4,000) | 50.00 | 1,000 | 58.59 | 7,571 |
| July Dec. 2008 | 14,500 | 63.62 | (4,000) | 50.00 | | | 10,403 |
| Jan. Dec. 2009 | 6,000 | 68.83 | (5,000) | 50.00 | 1,000 | 68.70 | 9,691 |
| | | | | | | | $ 10,255 |

*Natural Gas Derivative Instruments*

| Period | Daily Floor Volume (Mcf) | Average Floor Price (per Mcf) | Daily Cap Volume (Mcf) | Average Cap Price (per Mcf) | Daily Swap Volume (Mcf) | Average Swap Price (per Mcf) | Asset Fair Market Value (in thousands) |
|---|---|---|---|---|---|---|---|
| July Dec. 2007 | 36,500 | $ 6.85 | 2,000 | $ 9.85 | 10,000 | $ 4.99 | $ 1,782 |
| Jan. Dec. 2008 | 24,000 | 6.58 | 2,000 | 9.85 | | | 4,265 |
| Jan. Dec. 2009 | 4,000 | 7.70 | 2,000 | 9.85 | | | 754 |
| | | | | | | | $ 6,801 |

***Commodity Contracts Mark-to-Market Accounting: Floor Spreads***

In order to partially finance the cost of premiums on certain purchased floors, the Company may sell floors with a strike price below the strike price of the purchased floor. Together the two floors, known as a floor spread or put spread, have a lower premium cost than a traditional floor contract but provide price protection only down to the strike price of the short floor. During 2006, the Company entered into floor spreads with a $70 per Bbl purchased floor and a $50 per Bbl short floor for 4,000 Bbls/D in 2008 and 5,000 Bbls/D in 2009. As with the Company s other derivative contracts, these are marked-to-market each quarter through Derivative fair value loss in the accompanying Consolidated Statements of Operations. In the above table, the purchased floor component of these floor spreads has been included with the Company s other floor contracts and the short floor component is shown separately as negative volumes.

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***Commodity Contracts Current Period Impact***

As a result of derivative transactions for oil and natural gas, the Company recognized a pre-tax reduction in oil and natural gas revenues of approximately $13.4 million and $14.8 million during the three months ended June 30, 2007 and 2006, respectively, and $26.8 million and $31.3 million during the six months ended June 30, 2007 and 2006, respectively. The Company also recognized derivative fair value gains and losses related to (i) changes in the market value since the date of dedesignation of derivative contracts which were previously designated as hedges, (ii) changes in the market value of certain other commodity derivatives that were never designated as hedges, (iii) settlements on derivative contracts not designated as hedges, and (iv) ineffectiveness of derivative contracts designated as hedges prior to July 2006. The following table summarizes the components of derivative fair value loss for the three and six months ended June 30, 2007 and 2006:

| | Three months ended June 30, | | Six months ended June 30, | |
|---|---|---|---|---|
| | 2007 | 2006 | 2007 | 2006 |
| | (in thousands) | | | |
| Ineffectiveness on designated cash flow hedges | $ | $ (1,091) | $ | $ 1,748 |
| Mark-to-market loss on commodity contracts not designated as hedges | 10,315 | 12,368 | 64,125 | 13,461 |
| Settlements on commodity contracts | (3,549) | (483) | (11,745) | (2,109) |
| Total derivative fair value loss | $ 6,766 | $ 10,794 | $ 52,380 | $ 13,100 |

***Commodity Contracts Future Period Impact***

At June 30, 2007 and December 31, 2006, AOCL consisted entirely of deferred losses on commodity derivatives, net of tax, of $18.8 million and $35.3 million, respectively.

During the twelve months ending June 30, 2008, the Company expects to reclassify the remaining $29.7 million of deferred losses associated with its dedesignated commodity contracts from AOCL to oil and natural gas revenues. The Company also expects to reclassify the remaining $10.9 million of net deferred tax assets from AOCL to income tax benefit during the twelve months ending June 30, 2008.

**Note 7. Asset Retirement Obligations**

The Company s primary asset retirement obligations relate to future plugging and abandonment expenses on oil and natural gas properties and related facilities disposal. The Company does not include a market risk premium in its risk estimates because a reliable estimate cannot be determined. As of June 30, 2007, the Company had $5.5 million held in an escrow account from which funds are released only for reimbursement of plugging and abandonment expenses on its Bell Creek property. This amount is included in Other assets in the accompanying Consolidated Balance Sheet. The following table summarizes the changes in the Company s future abandonment liability, the long-term portion of which is recorded in Future abandonment cost on the accompanying Consolidated Balance Sheets, for the six months ended June 30, 2007 (in thousands):

| | |
|---|---|
| Future abandonment liability at January 1, 2007 | $ 19,841 |
| Wells drilled | 59 |
| Accretion of discount | 531 |
| Plugging and abandonment costs incurred | (253) |
| Revision of estimates | (604) |
| Disposition of properties | (959) |
| Acquisition of properties | 10,448 |

| | |
|---|---|
| Future abandonment liability at June 30, 2007 | $ 29,063 |

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**ENCORE ACQUISITION COMPANY**
**NOTES TO CONSOLIDATED FINANCIAL STATEMENTS Continued**
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**Note 8. Debt**

The Company s long-term debt consisted of the following as of the dates indicated:

| | June 30, 2007 | December 31, 2006 |
|---|---|---|
| | (in thousands) | |
| Revolving credit facilities | $ 707,000 | $ 68,000 |
| 6 1/4% Notes | 150,000 | 150,000 |
| 6% Notes, net of unamortized discount of $4,670 and $4,892, respectively | 295,330 | 295,108 |
| 7 1/4% Notes, net of unamortized discount of $1,368 and $1,412, respectively | 148,632 | 148,588 |
| Total | $ 1,300,962 | $ 661,696 |

***Revolving Credit Facilities***

Encore Acquisition Company Senior Secured Credit Agreement

On March 7, 2007, Encore entered into a five-year amended and restated credit agreement (the Encore Credit Agreement ) with a bank syndicate comprised of Bank of America, N.A. and other lenders, which amended and restated Encore s Amended and Restated Credit Agreement dated as of August 19, 2004, as amended.

The Encore Credit Agreement provides for revolving credit loans to be made to Encore from time to time and letters of credit to be issued from time to time for the account of Encore or any of its restricted subsidiaries. The aggregate amount of the commitments of the lenders under the Encore Credit Agreement is $1.25 billion. Availability under the Encore Credit Agreement is subject to a borrowing base, which was $900 million at June 30, 2007. The borrowing base is redetermined semi-annually and upon requested special redeterminations.

The Encore Credit Agreement matures on March 7, 2012. Encore s obligations under the Encore Credit Agreement are secured by a first-priority security interest in Encore s and its restricted subsidiaries proved oil and natural gas reserves and in the equity interests of Encore s restricted subsidiaries. In addition, Encore s obligations under the Encore Credit Agreement are guaranteed by its restricted subsidiaries.

Loans under the Encore Credit Agreement are subject to varying rates of interest based on (i) the total amount outstanding in relation to the borrowing base and (ii) whether the loan is a Eurodollar loan or a base rate loan. Eurodollar loans bear interest at the Eurodollar rate plus the applicable margin indicated in the following table, and base rate loans bear interest at the base rate plus the applicable margin indicated in the following table:

| Ratio of Total Outstandings to Borrowing Base | Applicable Margin for Eurodollar Loans | Applicable Margin for Base Rate Loans |
|---|---|---|
| Less than .50 to 1 | 1.000% | 0.000% |
| From .50 to 1 but less than .75 to 1 | 1.250% | 0.000% |
| From .75 to 1 but less than .90 to 1 | 1.500% | 0.250% |
| Greater than or equal to .90 to 1 | 1.750% | 0.500% |

The Eurodollar rate for any interest period (either one, two, three or six months, as selected by Encore) is the rate per year equal to LIBOR, as published by Reuters or another source designated by Bank of America, N.A., for deposits in dollars for a similar interest period. The base rate is calculated as the higher of (i) the annual rate of interest announced by Bank of America, N.A. as its prime rate and (ii) the federal funds effective rate plus 0.5 percent.

As of June 30, 2007, the aggregate principal amount of loans outstanding under the Encore Credit Agreement was $592 million and the aggregate face amount of outstanding letters of credit was $20 million, all of which related to the

Company s joint development agreement with ExxonMobil Corporation ( ExxonMobil ) (see Note 14 for additional discussion of this agreement). Any outstanding letters of credit reduce the availability under the Encore Credit Agreement. Borrowings under the Encore Credit Agreement may be repaid from time to time without penalty.

The Encore Credit Agreement contains covenants that include, among others:

- a prohibition against incurring debt, subject to permitted exceptions;
- a prohibition against paying dividends or making distributions, purchasing or redeeming capital stock, or prepaying indebtedness, subject to permitted exceptions;

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**NOTES TO CONSOLIDATED FINANCIAL STATEMENTS Continued**
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indebtedness, subject to permitted exceptions;

a restriction on creating liens on Encore s and its restricted subsidiaries assets, subject to permitted exceptions;

restrictions on merging and selling assets outside the ordinary course of business;

restrictions on use of proceeds, investments, transactions with affiliates, or change of principal business;

a provision limiting oil and natural gas hedging transactions (other than puts) to a volume not exceeding 75 percent of anticipated production from proved producing reserves;

a requirement that Encore maintain a ratio of consolidated current assets to consolidated current liabilities of not less than 1.0 to 1.0; and

a requirement that Encore maintain a ratio of consolidated EBITDA (as defined in the Encore Credit Agreement) to the sum of consolidated net interest expense plus letter of credit fees of not less than 2.5 to 1.0.

The Encore Credit Agreement contains customary events of default. If an event of default occurs and is continuing, lenders with a majority of the aggregate commitments may require Bank of America, N.A. to declare all amounts outstanding under the Encore Credit Agreement to be immediately due and payable. The Company was in compliance with all of the debt covenants under the Encore Credit Agreement as of June 30, 2007.

Encore incurs a commitment fee on the unused portion of the Encore Credit Agreement determined based on the ratio of amounts outstanding under the Encore Credit Agreement to the borrowing base in effect on such date. The following table summarizes the calculation of the commitment fee under the Encore Credit Agreement:

| Ratio of Total Outstandings to Borrowing Base | Commitment Fee Percentage |
|---|---|
| Less than .50 to 1 | 0.250% |
| From .50 to 1 but less than .75 to 1 | 0.300% |
| From .75 to 1 but less than .90 to 1 | 0.375% |
| Greater than or equal to .90 to 1 | 0.375% |

Encore Energy Partners Operating LLC Credit Agreement

On March 7, 2007, EEPO entered into a five-year credit agreement (the EEPO Credit Agreement ) with a bank syndicate comprised of Bank of America, N.A. and other lenders. The EEPO Credit Agreement provides for revolving credit loans to be made to EEPO from time to time and letters of credit to be issued from time to time for the account of EEPO or any of its restricted subsidiaries.

The aggregate amount of the commitments of the lenders under the EEPO Credit Agreement is $300 million. Availability under the EEPO Credit Agreement is subject to a borrowing base, which was $115 million at June 30, 2007, and EEPO has the option of borrowing up to $10 million in excess of the borrowing base for a certain period of time following the closing date. The borrowing base is redetermined semi-annually and upon requested special redeterminations.

The EEPO Credit Agreement matures on March 7, 2012. EEPO s obligations under the EEPO Credit Agreement are secured by a first-priority security interest in EEPO s and its restricted subsidiaries proved oil and natural gas reserves and in the equity interests of EEPO and its restricted subsidiaries. In addition, EEPO s obligations under the EEPO Credit Agreement are guaranteed by its direct parent, Encore Energy Partners LP, a Delaware limited partnership (the Partnership ), and EEPO s restricted subsidiaries. Obligations under the EEPO Credit Agreement are non-recourse to

Encore and its restricted subsidiaries.

Loans under the EEPO Credit Agreement are subject to varying rates of interest based on the same provisions as the Encore Credit Agreement.

As of June 30, 2007, the aggregate principal amount of loans outstanding under the EEPO Credit Agreement was $115 million and there were no outstanding letters of credit. Any outstanding letters of credit reduce the availability under the EEPO Credit Agreement. Borrowings under the EEPO Credit Agreement may be repaid from time to time without penalty.

The EEPO Credit Agreement contains covenants that include, among others:

a prohibition against incurring debt, subject to permitted exceptions;

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a prohibition against paying dividends or making distributions prior to the IPO Effective Date (as defined in the EEPO Credit Agreement), purchasing or redeeming capital stock, or prepaying indebtedness, subject to permitted exceptions;

a restriction on creating liens on the assets of the Partnership, EEPO and its restricted subsidiaries, subject to permitted exceptions;

restrictions on merging and selling assets outside the ordinary course of business;

restrictions on use of proceeds, investments, transactions with affiliates, or change of principal business;

a provision limiting oil and natural gas hedging transactions (other than puts) to a volume not exceeding 75 percent of anticipated production from proved producing reserves;

a requirement that EEPO maintain a ratio of consolidated current assets to consolidated current liabilities of not less than 1.0 to 1.0;

a requirement that EEPO maintain a ratio of consolidated EBITDA (as defined in the EEPO Credit Agreement) to the sum of consolidated net interest expense plus letter of credit fees of not less than 2.5 to 1.0; and

a requirement that EEPO maintain a ratio of consolidated funded debt (excluding certain related party debt) to consolidated adjusted EBITDA (as defined in the EEPO Credit Agreement) of not more than 3.5 to 1.0.

The EEPO Credit Agreement contains customary events of default. If an event of default occurs and is continuing, lenders with a majority of the aggregate commitments may require Bank of America, N.A. to declare all amounts outstanding under the EEPO Credit Agreement to be immediately due and payable. At June 30, 2007, EEPO was in violation of the EEPO Credit Agreement covenant that requires it to maintain a ratio of consolidated EBITDA (as defined in the EEPO Credit Agreement) to the sum of consolidated net interest expense plus letter of credit fees of not less than 2.5 to 1.0. EEPO requested and obtained a waiver from the bank syndicate for the June 30, 2007 violation. Amounts outstanding under the EEPO Credit Agreement have continued to be classified as long-term debt in the accompanying Consolidated Balance Sheet as Encore has the ability and intent to refinance borrowings, on a long-term basis, should any amounts become due and payable within the next twelve months under the EEPO Credit Agreement. EEPO was in compliance with all other debt covenants under the EEPO Credit Agreement as of June 30, 2007.

EEPO incurs a commitment fee on the unused portion of the EEPO Credit Agreement determined based on the same provisions as the Encore Credit Agreement.

**Note 9. Income Taxes**

The components of the income tax benefit (provision) were as follows for the six months ended June 30, 2007 and 2006:

| | Six months ended June 30, | |
|---|---|---|
| | **2007** | **2006** |
| | (in thousands) | |
| Federal: | | |
| Current | $ (249) | $ (1,102) |
| Deferred | 7,747 | (22,194) |

| | | |
|---|---|---|
| Total federal | 7,498 | (23,296) |
| State, net of federal benefit/expense: | | |
| Current | | |
| Deferred | (2) | (3,017) |
| Total state | (2) | (3,017) |
| Income tax benefit (provision) | $ 7,496 | $ (26,313) |

The following table reconciles income tax benefit (provision) with income tax at the Federal statutory rate for the six months ended June 30, 2007 and 2006:

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**ENCORE ACQUISITION COMPANY**
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| | Six months ended June 30, 2007 | Six months ended June 30, 2006 |
|---|---|---|
| | (in thousands) | |
| Income (loss) before income taxes | $ (21,753) | $ 66,484 |
| Tax at statutory rate | $ 7,614 | $ (23,269) |
| State income taxes, net of federal benefit/expense | 519 | (1,550) |
| Enactment of the Texas margin tax | | (1,295) |
| Change in estimated future tax rate | (542) | |
| Permanent and other | (95) | (199) |
| Income tax benefit (provision) | $ 7,496 | $ (26,313) |

On January 1, 2007, the Company adopted the provisions of FIN 48. FIN 48 clarifies the accounting for uncertainty in income taxes recognized in a company s financial statements in accordance with SFAS No. 109, *Accounting for Income Taxes* ( SFAS 109 ). FIN 48 prescribes a recognition threshold and measurement attribute for the financial statement recognition and measurement of a tax position taken or expected to be taken in a tax return. The Company and its subsidiaries file income tax returns in the U.S. federal jurisdiction and various state jurisdictions. Subject to statutory exceptions that allow for a possible extension of the assessment period, the Company is no longer subject to U.S. federal, state, and local income tax examinations for years prior to 2003.

The Company has performed its evaluation of tax positions and has determined that the adoption of FIN 48 did not have a material impact on the Company s financial condition, results of operations, or cash flows. This evaluation is a review of the appropriate recognition threshold for each tax position recognized in the Company s financial statements. The evaluation included, but was not limited to: (1) a review of documentation of tax positions taken on previous returns including an assessment of whether the Company followed industry practice or the applicable requirements under the tax code, (2) a review of open tax returns (on a jurisdiction by jurisdiction basis) as well as supporting documentation used to support those tax returns, (3) a review of the results of past tax examinations, (4) a review of whether tax returns have been filed in all appropriate jurisdictions, (5) a review of existing permanent and temporary differences, and (6) consideration of any tax planning strategies that may have been used to support realization of deferred tax assets. Based on this evaluation, the Company did not identify any tax positions that did not meet the highly certain positions threshold. As a result, no additional tax expense, interest, or penalties have been accrued as a result of the review.

The Company includes interest assessed by the taxing authorities in Interest expense and penalties related to income taxes in Other expense on its Consolidated Statements of Operations. For the six months ended June 30, 2007 and 2006, the Company recorded only a nominal amount of interest and penalties on certain tax positions.

**Note 10. Earnings Per Share ( EPS )**

The following table reflects EPS computations for the three and six months ended June 30, 2007 and 2006:

| | Three months ended June 30, 2007 | Three months ended June 30, 2006 | Six months ended June 30, 2007 | Six months ended June 30, 2006 |
|---|---|---|---|---|
| | (in thousands, except per share data) | | | |
| **Numerator:** | | | | |

| | | | | |
|---|---|---|---|---|
| Net income (loss) | $ 15,171 | $ 22,235 | $ (14,257) | $ 40,171 |
| **Denominator:** | | | | |
| Denominator for basic EPS: | | | | |
| Weighted average shares outstanding | 53,143 | 52,631 | 53,111 | 50,724 |
| Effect of dilutive options and diluted restricted stock (a) | 877 | 901 | | 939 |
| Denominator for diluted EPS | 54,020 | 53,532 | 53,111 | 51,663 |
| **Net income (loss) per common share:** | | | | |
| Basic | $ 0.29 | $ 0.42 | $ (0.27) | $ 0.79 |
| Diluted | $ 0.28 | $ 0.42 | $ (0.27) | $ 0.78 |

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**NOTES TO CONSOLIDATED FINANCIAL STATEMENTS Continued**
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(a) Options to purchase 98,562 shares and 107,360 shares of common stock were outstanding but not included in the above calculation of diluted EPS for the three months ended June 30, 2007 and 2006, respectively, because their effect would have been antidilutive. Options to purchase 1,463,487 shares of common stock were outstanding but not included in the above calculation of diluted EPS for the six months ended June 30, 2007 because their effect would have been antidilutive. The effect of dilutive options and diluted restricted stock for the six months ended June 30, 2006 is an average of the effect of the dilutive options and diluted restricted stock for the first two quarters.

**Note 11. Incentive Stock Plan**

During 2000, the Company s Board of Directors (the Board ) and stockholders approved the 2000 Incentive Stock Plan (the Plan ). The Plan was amended and restated effective March 18, 2004. The purpose of the Plan is to attract, motivate, and retain selected employees of the Company and to provide the Company with the ability to provide incentives more directly linked to the profitability of the business and increases in shareholder value. All directors and full-time regular employees of the Company and its subsidiaries and affiliates are eligible to be granted awards under the Plan. The total number of shares of common stock reserved for issuance pursuant to the Plan is 4,500,000. As of June 30, 2007, there were 814,424 shares available for issuance under the Plan. Shares delivered or withheld for payment of the exercise price of an option, shares withheld for payment of tax withholding, or shares subject to options or other awards that expire or are terminated and restricted shares that are forfeited will again become available for issuance under the Plan. The Plan provides for the granting of cash awards, incentive stock options, non-qualified stock options, restricted stock, and stock appreciation rights at the discretion of the Compensation Committee of the Board. The Board also has a Restricted Stock Award Committee having Jon S. Brumley, the Company s Chief Executive Officer and President, as its sole member. The Restricted Stock Award Committee may grant certain awards of restricted stock to non-executive employees at its discretion.

The Plan contains the following individual limits:

- an employee may not be granted awards covering or relating to more than 225,000 shares of common stock in any calendar year;

- a non-employee director may not be granted awards covering or relating to more than 15,000 shares of common stock in any calendar year; and

- an employee may not receive awards consisting of cash (including cash awards that are granted as performance awards) in respect of any calendar year having a value determined on the grant date in excess of $1.0 million.

All options that have been granted under the Plan have a strike price equal to the fair market value of the Company s common stock on the date of grant. Additionally, all options have a ten-year life and vest equally over a three-year period. Restricted stock granted under the Plan vests over varying periods from one to five years, subject to performance-based vesting for certain members of senior management.

The compensation cost related to the Plan that has been recorded in the accompanying Consolidated Statements of Operations for the six months ended June 30, 2007 and 2006 was $5.5 million and $4.9 million, respectively. The income tax benefit related to the Plan that has been recorded in the accompanying Consolidated Statements of Operations for the six months ended June 30, 2007 and 2006 was $2.0 million and $1.8 million, respectively. During the six months ended June 30, 2007 and 2006, the Company also capitalized $0.7 million and $0.4 million, respectively, of non-cash stock-based compensation cost as a component of Properties and equipment in the accompanying Consolidated Balance Sheets. Non-cash stock-based compensation expense has been allocated to lease operations expense, general and administrative expense, and exploration expense based on the allocation of the respective employees cash compensation.

***Stock Options***

The fair value of each option award granted during the six months ended June 30, 2007 and 2006 was estimated on the date of grant using the Black-Scholes option valuation model based on the assumptions noted in the following table. The expected volatility is based on the historical volatility of the Company s stock for a period of time commensurate with the expected term of the award. For options granted in the six months ended June 30, 2007 and 2006, the Company used the simplified method prescribed by SEC Staff Accounting Bulletin No. 107 to estimate the expected term of the options, which is calculated as the average midpoint between each vesting date and the life of the option. The risk-free rate is based on the U.S Treasury yield curve in effect at the time of grant for periods commensurate with the expected terms of the options.

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| | Six months ended June 30, 2007 | 2006 |
|---|---|---|
| Expected volatility | 35.7% | 42.8% |
| Expected dividend yield | 0.0% | 0.0% |
| Expected term (in years) | 6.0 | 6.0 |
| Risk-free interest rate | 4.8% | 4.6% |

The following table summarizes the change in the number of outstanding options and the related weighted average strike prices during the six months ended June 30, 2007:

| | Number of Options | Weighted Average Strike Price | Weighted Average Remaining Contractual Term | Aggregate Intrinsic Value (in thousands) |
|---|---|---|---|---|
| Outstanding at January 1, 2007 | 1,337,118 | $ 14.44 | | |
| Granted | 200,059 | 25.73 | | |
| Forfeited | (12,690) | 28.96 | | |
| Exercised | (61,000) | 13.33 | | |
| Outstanding at June 30, 2007 | 1,463,487 | 15.91 | 6.1 | $ 17,733 |
| Exercisable at June 30, 2007 | 1,172,788 | 13.15 | 5.3 | 17,289 |

The weighted average fair value per share of individual options granted during the six months ended June 30, 2007 and 2006 was $11.16 and $14.96, respectively. The total intrinsic value of options exercised during the six months ended June 30, 2007 and 2006 was $0.8 million and $2.3 million, respectively. During the six months ended June 30, 2007 and 2006, the Company received proceeds from the exercise of stock options of $0.8 million and $2.1 million, respectively, and realized tax benefits related to stock options of $0.3 million and $0.9 million, respectively. At June 30, 2007, the Company had $2.7 million of total unrecognized compensation cost related to unvested stock options, which is expected to be recognized over a weighted average period of 2.3 years.

***Restricted Stock***

During the six months ended June 30, 2007 and 2006, the Company recognized expense related to restricted stock of $4.5 million and $4.2 million, respectively, and realized tax benefits related to restricted stock of $1.7 million and $1.6 million, respectively. A summary of the status of the Company s unvested restricted stock outstanding as of June 30, 2007, and changes during the six months then ended, is presented below:

| | Number of Shares | Weighted Average Grant Date Fair Value |
|---|---|---|
| Outstanding at January 1, 2007 | 828,619 | $ 26.17 |
| Granted | 342,133 | 25.90 |

| | | |
|---|---|---|
| Vested | (118,273) | 25.40 |
| Forfeited | (36,459) | 26.51 |
| Outstanding at June 30, 2007 | 1,016,020 | 26.16 |

As of June 30, 2007, there were 840,830 shares of unvested restricted stock outstanding, dependent only on the passage of time and continued employment for vesting, 164,658 shares of which were granted during the six months ended June 30, 2007. Additionally, as of June 30, 2007, there were 175,190 shares of unvested restricted stock outstanding that not only depend on the passage of time and continued employment, but on certain performance measures for vesting, all of which were granted during the six months ended June 30, 2007.

As of June 30, 2007, there was $14.8 million of total unrecognized compensation cost related to unvested, outstanding

**ENCORE ACQUISITION COMPANY**
**NOTES TO CONSOLIDATED FINANCIAL STATEMENTS Continued**
(unaudited)

restricted stock, which is expected to be recognized over a weighted average period of 3.0 years. During the six months ended June 30, 2007 and 2006, there were 118,273 shares and 27,909 shares, respectively, of restricted stock that vested and employees elected to satisfy minimum tax withholding obligations related to these shares by allowing the Company to withhold 5,545 shares and 6,553 shares of common stock, respectively. These shares are treated as treasury stock by the Company until the shares are formally retired and have been reflected as such in the accompanying consolidated financial statements.

**Note 12. Comprehensive Income**

Components of comprehensive income, net of related tax, are as follows:

| | Three months ended June 30, | | Six months ended June 30, | |
|---|---|---|---|---|
| | 2007 | 2006 | 2007 | 2006 |
| | (in thousands) | | | |
| Net income (loss) | $ 15,171 | $ 22,235 | $ (14,257) | $ 40,171 |
| Amortization of deferred loss on commodity derivatives | 8,373 | 11,304 | 16,554 | 19,554 |
| Amortization of deferred gain on interest rate swap | | (15) | | (29) |
| Comprehensive income | $ 23,544 | $ 33,524 | $ 2,297 | $ 59,696 |

**Note 13. Financial Statements of Subsidiary Guarantors**

Effective February 2007, the Company formed certain non-guarantor subsidiaries in anticipation of forming a master limited partnership ( MLP ). See Note 16. MLP for additional discussion. As of June 30, 2007, certain of the Company s wholly- owned subsidiaries were subsidiary guarantors of the Company s outstanding notes. The subsidiary guarantees are full and unconditional, and joint and several. The subsidiary guarantors may, without restriction, transfer funds to the Company in the form of cash dividends, loans, and advances. In accordance with SEC rules, the Company has prepared condensed consolidating financial statements in order to quantify the assets and results of operations of the subsidiary guarantors. The following Condensed Consolidating Balance Sheet as of June 30, 2007, Condensed Consolidating Statements of Operations and Comprehensive Income (Loss) for the three and six months ended June 30, 2007, and Condensed Consolidating Statement of Cash Flows for the six months ended June 30, 2007 present consolidating financial information for Encore Acquisition Company ( Parent ) on a stand alone, unconsolidated basis, and its combined guarantor and combined non-guarantor subsidiaries. The guarantor subsidiaries are EAP Energy, Inc., EAP Properties Inc., EAP Operating Inc., EAP Energy Services, L.P., Encore Operating, L.P., and Encore Operating Louisiana, LLC. The non-guarantor subsidiaries are EEPO, Encore Partners GP Holdings LLC, Encore Energy Partners LP, Encore Partners LP Holdings LLC, Encore Energy Partners GP LLC, and Encore Clear Fork Pipeline LLC. All intercompany investments in, loans due to/from, subsidiary equity, income and expenses between the Parent, the guarantor subsidiaries, and non-guarantor subsidiaries are shown prior to final consolidation with the Parent and then eliminated to arrive at consolidated totals per the accompanying consolidated financial statements of Encore. Prior to February 2007, all of the Company s subsidiaries were subsidiary guarantors of the Company s outstanding senior notes. Therefore, comparative condensed consolidating financial statements are not presented as of December 31, 2006 or for the three and six months ended June 30, 2006.

Income taxes in the Condensed Consolidating Statements of Operations and Comprehensive Income (Loss) are shown as an expense of the Parent as the Company files a consolidated return. Additionally, the Company s net current deferred tax asset and net long-term deferred tax liability have been included in the balance sheet of the Parent in the Condensed Consolidating Balance Sheet.

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**ENCORE ACQUISITION COMPANY**
**NOTES TO CONSOLIDATED FINANCIAL STATEMENTS Continued**
(unaudited)
**CONDENSED CONSOLIDATING BALANCE SHEET**
**June 30, 2007**
(in thousands)

| | Parent | Guarantor Subsidiaries | Non-Guarantor Subsidiaries | Eliminations | Consolidated Total |
|---|---|---|---|---|---|
| **ASSETS** | | | | | |
| Current assets: | | | | | |
| Cash and cash equivalents | $ | $ 3,590 | $ 1,348 | $ | $ 4,938 |
| Other current assets | 113,993 | 153,631 | 16,448 | (101,325) | 182,747 |
| Total current assets | 113,993 | 157,221 | 17,796 | (101,325) | 187,685 |
| Properties and equipment, at cost - successful efforts method: | | | | | |
| Proved properties, including wells and related equipment | | 2,309,293 | 327,492 | | 2,636,785 |
| Unproved properties | | 51,482 | | | 51,482 |
| Accumulated depletion, depreciation, and amortization | | (384,466) | (9,901) | | (394,367) |
| | | 1,976,309 | 317,591 | | 2,293,900 |
| Other property and equipment, net | | 10,642 | 65 | | 10,707 |
| Other assets, net | 136,397 | 262,340 | 17,649 | (247,282) | 169,104 |
| Investment in subsidiaries | 2,052,359 | | | (2,052,359) | |
| Total assets | $ 2,302,749 | $ 2,406,512 | $ 353,101 | $ (2,400,966) | $ 2,661,396 |
| **LIABILITIES AND STOCKHOLDERS EQUITY** | | | | | |
| Current liabilities | $ 12,152 | $ 274,727 | $ 127,456 | $ (216,325) | $ 198,010 |
| Deferred taxes | 278,823 | | | | 278,823 |
| Long-term debt | 1,185,962 | 123,641 | 123,641 | (132,282) | 1,300,962 |
| Other liabilities | | 49,146 | 8,643 | | 57,789 |
| Total liabilities | 1,476,937 | 447,514 | 259,740 | (348,607) | 1,835,584 |

| | | | | | |
|---|---|---|---|---|---|
| Commitments and contingencies (see Note 14) | | | | | |
| Total stockholders equity | 825,812 | 1,958,998 | 93,361 | (2,052,359) | 825,812 |
| Total liabilities and stockholders equity | $ 2,302,749 | $ 2,406,512 | $ 353,101 | $ (2,400,966) | $ 2,661,396 |

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**ENCORE ACQUISITION COMPANY**
**NOTES TO CONSOLIDATED FINANCIAL STATEMENTS Continued**
(unaudited)
**CONDENSED CONSOLIDATING STATEMENT OF OPERATIONS AND COMPREHENSIVE INCOME (LOSS)**
**For the Three Months Ended June 30, 2007**
(in thousands)

| | Parent | Guarantor Subsidiaries | Non-Guarantor Subsidiaries | Eliminations | Consolidated Total |
|---|---|---|---|---|---|
| Revenues: | | | | | |
| Oil | $ | $ 119,508 | $ 16,088 | $ | $ 135,596 |
| Natural gas | | 44,950 | 181 | | 45,131 |
| Marketing | | 5,302 | 3,614 | | 8,916 |
| Total revenues | | 169,760 | 19,883 | | 189,643 |
| Expenses: | | | | | |
| Production: | | | | | |
| Lease operations | | 34,202 | 3,350 | | 37,552 |
| Production, ad valorem, and severance taxes | | 17,139 | 2,093 | | 19,232 |
| Depletion, depreciation, and amortization | | 44,924 | 7,394 | | 52,318 |
| Exploration | | 3,415 | | | 3,415 |
| General and administrative | 13 | 5,552 | 623 | | 6,188 |
| Marketing | | 5,232 | 3,275 | | 8,507 |
| Derivative fair value loss | | 3,952 | 2,814 | | 6,766 |
| Other operating | 42 | 4,550 | 159 | | 4,751 |
| Total expenses | 55 | 118,966 | 19,708 | | 138,729 |
| Operating income (loss) | (55) | 50,794 | 175 | | 50,914 |
| Other income (expenses): | | | | | |
| Interest | (10,219) | (18,599) | (5,342) | 6,340 | (27,820) |
| Equity income (loss) from subsidiaries | 30,773 | | | (30,773) | |
| Other | 3,196 | 3,718 | 27 | (6,340) | 601 |
| Total other income (expenses) | 23,750 | (14,881) | (5,315) | (30,773) | (27,219) |
| Income (loss) before income taxes | 23,695 | 35,913 | (5,140) | (30,773) | 23,695 |
| Income tax provision | (8,524) | | | | (8,524) |

| | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|
| Net income (loss) | 15,171 | | 35,913 | | (5,140) | | (30,773) | | 15,171 |
| Amortization of deferred hedge losses, net of tax | 8,373 | | | | | | | | 8,373 |
| Comprehensive income (loss) | $ 23,544 | $ | 35,913 | $ | (5,140) | $ | (30,773) | $ | 23,544 |

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**ENCORE ACQUISITION COMPANY**
**NOTES TO CONSOLIDATED FINANCIAL STATEMENTS Continued**
(unaudited)
**CONDENSED CONSOLIDATING STATEMENT OF OPERATIONS AND COMPREHENSIVE INCOME (LOSS)**
**For the Six Months Ended June 30, 2007**
(in thousands)

| | Parent | Guarantor Subsidiaries | Non-Guarantor Subsidiaries | Eliminations | Consolidated Total |
|---|---|---|---|---|---|
| Revenues: | | | | | |
| Oil | $ | $ 197,888 | $ 20,331 | $ | $ 218,219 |
| Natural gas | | 77,779 | 330 | | 78,109 |
| Marketing | | 19,005 | 4,852 | | 23,857 |
| Total revenues | | 294,672 | 25,513 | | 320,185 |
| Expenses: | | | | | |
| Production: | | | | | |
| Lease operations | | 63,754 | 4,318 | | 68,072 |
| Production, ad valorem, and severance taxes | | 29,017 | 2,730 | | 31,747 |
| Depletion, depreciation, and amortization | | 77,445 | 9,901 | | 87,346 |
| Exploration | | 14,936 | | | 14,936 |
| General and administrative | 37 | 12,700 | 811 | | 13,548 |
| Marketing | | 19,163 | 4,355 | | 23,518 |
| Derivative fair value loss | | 45,883 | 6,497 | | 52,380 |
| Other operating | 83 | 7,050 | 183 | | 7,316 |
| Total expenses | 120 | 269,948 | 28,795 | | 298,863 |
| Operating income (loss) | (120) | 24,724 | (3,282) | | 21,322 |
| Other income (expenses): | | | | | |
| Interest | (41,304) | (3,641) | (6,444) | 7,282 | (44,107) |
| Equity income (loss) from subsidiaries | 16,046 | | | (16,046) | |
| Other | 3,625 | 4,662 | 27 | (7,282) | 1,032 |
| Total other income (expenses) | (21,633) | 1,021 | (6,417) | (16,046) | (43,075) |
| Income (loss) before income taxes | (21,753) | 25,745 | (9,699) | (16,046) | (21,753) |
| Income tax benefit (provision) | 7,496 | | | | 7,496 |

| | | | | | |
|---|---|---|---|---|---|
| Net income (loss) | (14,257) | 25,745 | (9,699) | (16,046) | (14,257) |
| Amortization of deferred hedge losses, net of tax | 16,554 | | | | 16,554 |
| Comprehensive income (loss) | $ 2,297 | $ 25,745 | $ (9,699) | $ (16,046) | $ 2,297 |

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**ENCORE ACQUISITION COMPANY**
**NOTES TO CONSOLIDATED FINANCIAL STATEMENTS    Continued**
(unaudited)
**CONDENSED CONSOLIDATING STATEMENT OF CASH FLOWS**
**For the Six Months Ended June 30, 2007**
(in thousands)

| | Parent | Guarantor Subsidiaries | Non-Guarantor Subsidiaries | Eliminations | Consolidated Total |
|---|---|---|---|---|---|
| Cash flows from operating activities: | | | | | |
| Net cash provided by operating activities | $ | $ 79,732 | $ 1,593 | $ | $ 81,325 |
| Cash flows from investing activities: | | | | | |
| Proceeds from disposition of assets | | 291,454 | | | 291,454 |
| Acquisition of oil and natural gas properties | | (452,361) | (327,215) | | (779,576) |
| Development of oil and natural gas properties | | (187,227) | | | (187,227) |
| Intercompany loans | (120,000) | (120,000) | | 240,000 | |
| Investments in subsidiaries | (379,542) | | | 379,542 | |
| Other | | (25,701) | (71) | | (25,772) |
| Net cash provided by (used in) investing activities | (499,542) | (493,835) | (327,286) | 619,542 | (701,121) |
| Cash flows from financing activities: | | | | | |
| Exercise of stock options and vesting of restricted stock, net of treasury stock purchases | 497 | | | | 497 |
| Proceeds from long-term debt | 1,001,000 | 120,000 | 250,500 | (240,000) | 1,131,500 |
| Payments on long-term debt | (477,000) | | (15,500) | | (492,500) |
| Net equity contributions | | 285,884 | 93,658 | (379,542) | |
| Other | (24,955) | 11,046 | (1,617) | | (15,526) |
| Net cash provided by (used in) financing activities | 499,542 | 416,930 | 327,041 | (619,542) | 623,971 |
| Increase in cash and cash equivalents | | 2,827 | 1,348 | | 4,175 |
| Cash and cash equivalents, beginning of period | | 763 | | | 763 |

| | | | | | |
|---|---|---|---|---|---|
| Cash and cash equivalents, end of period | $ | $ 3,590 | $ 1,348 | $ | $ 4,938 |

**Note 14. Commitments and Contingencies**

***Litigation***

The Company is a party to ongoing legal proceedings in the ordinary course of business. Management does not believe the result of these proceedings will have a material adverse effect on the Company.

***ExxonMobil***

In March 2006, Encore entered into a joint development agreement with ExxonMobil to develop legacy natural gas fields in West Texas. Under the terms of the agreement, Encore will have the opportunity to develop approximately 100,000 gross acres. Encore will earn 30 percent of ExxonMobil s working interest and 22.5 percent of ExxonMobil s net revenue interest in each well drilled. Encore will operate each well during the drilling and completion phase, after which ExxonMobil will assume operational control of the well.

Encore will earn the right to participate in all fields by drilling a total of 24 commitment wells. During the commitment phase, ExxonMobil will have the option to receive non-recourse advanced funds from Encore attributable to ExxonMobil s 70 percent working interest in each commitment well. Once a commitment well is producing, ExxonMobil will repay 95 percent of the advanced funds plus accrued interest assessed on the unpaid balance through Encore s monthly receipt of future proceeds of oil and natural gas sales. As an alternative to receiving advanced funds during the commitment phase, ExxonMobil can elect to pay their share of capital costs for each well. After Encore has fulfilled its obligations under the commitment phase, Encore will be entitled to a 30 percent working interest in future drilling locations. Encore will have the right to propose and drill wells for as long as Encore is engaged in continuous drilling operations.

During the six months ended June 30, 2007 and the year ended December 31, 2006, we advanced $26.4 million and $22.4 million, respectively, to ExxonMobil for its portion of capital related to drilling commitment wells, of which $45.6 million and $21.0 million remained outstanding at June 30, 2007 and December 31, 2006, respectively. At June 30, 2007, $2.5 million is included in Accounts receivable and $43.1 million is included in Long-term receivables on the accompanying Consolidated

**ENCORE ACQUISITION COMPANY**
**NOTES TO CONSOLIDATED FINANCIAL STATEMENTS Continued**
(unaudited)

Balance Sheets based on when Encore expects repayment. At December 31, 2006, $3.0 million is included in Accounts receivable and $18.0 million is included in Long-term receivables on the accompanying Consolidated Balance Sheets. As of June 30, 2007, Encore had 7 additional wells to drill in order to fulfill its drilling obligation under the joint development agreement.

**Note 15. Related Party Transactions**

The Company paid $1.1 million and $1.6 million to affiliates of Hanover Compressor Company ( Hanover ) during the six months ended June 30, 2007 and 2006, respectively, for compressors and field compression services. Mr. I. Jon Brumley, the Company s Chairman of the Board, also serves as a director of Hanover.

The Company also received $18.7 million and $3.8 million from affiliates of Tesoro Corporation ( Tesoro ) during the six months ended June 30, 2007 and 2006, respectively, related to its working interest in wells operated by Encore. Mr. John V. Genova, a member of the Board, is employed by Tesoro.

**Note 16. MLP**

On January 17, 2007, the Company announced an intention to form an MLP that will engage in an initial public offering of common units representing limited partner interests. The MLP was formed on February 13, 2007 and owns certain oil and gas properties and related assets in the Big Horn Basin of Wyoming and Montana. At the time of the initial public offering, the Company plans to contribute to the MLP certain of its legacy oil and gas properties in the Permian Basin of West Texas. Any sale of securities in the MLP would be registered under the Securities Act of 1933, and such units would only be offered and sold by means of a prospectus. This Report does not constitute an offer to sell or the solicitation of any offer to buy any securities of the MLP, and there will not be any sale of any such securities in any state in which such offer, solicitation, or sale would be unlawful prior to registration or qualification under the securities laws of such state.

In May 2007, the board of directors of Encore Energy Partners GP LLC, a wholly owned subsidiary of Encore, issued 550,000 management incentive units to the executive officers of Encore Energy Partners GP LLC. A management incentive unit is a limited partner interest in the MLP that entitles the holder to an initial quarterly distribution of $0.35 (or $1.40 on an annualized basis) to the extent paid to the MLP s common unitholders and to increasing distributions upon the achievement of 10 percent compounding increases in the MLP s distribution rate to common unitholders subject to a maximum limit of 5.1 percent on the aggregate distributions payable to holders of management incentive units. A management incentive unit is also convertible into common units upon the occurrence of certain events subject to a maximum limit of 5.1 percent on the aggregate number of common units issuable to holders of management incentive units. The holders of the management incentive units do not receive any cash distributions until the MLP's initial public offering is completed.

Upon completion of the MLP's initial public offering, the management incentive units will partially vest, at which point the MLP will recognize an expense for the estimated fair value of the vested portion of the units. The MLP will recognize additional expenses over at least the following two-year period as the management incentive units continue to vest.

**Note 17. Subsequent Events**

Subsequent to June 30, 2007, the Company entered into a costless collar with a $65.00 per Bbl floor and a $79.05 per Bbl ceiling for 500 Bbls/D in 2010 and a floor with a $65.00 per Bbl strike price for 500 Bbls/D in 2010. The Company paid a premium of $1.0 million in connection with the floor contract.

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ENCORE ACQUISITION COMPANY

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

This document contains forward-looking statements, which give our current expectations or forecasts of future events. Actual results may differ materially from those discussed in our forward-looking statements due to many factors, including, but not limited to, those set forth under Item 1A. Risk Factors in our Annual Report on Form 10-K for the year ended December 31, 2006. The following discussion should be read in conjunction with the consolidated financial statements and notes thereto included in Item 1. Financial Statements of this Report and in Item 8. Financial Statements and Supplementary Data of our 2006 Annual Report on Form 10-K.

**Introduction**

In this management s discussion and analysis of financial condition and results of operations, the following will be discussed and analyzed:

- Second Quarter 2007 Highlights
- Results of Operations
  - Comparison of Quarter Ended June 30, 2007 to Quarter Ended June 30, 2006
  - Comparison of Six Months Ended June 30, 2007 to Six Months Ended June 30, 2006
- Capital Resources
- Capital Commitments
- Liquidity
- Contingencies
- Critical Accounting Policies and Estimates
- New Accounting Pronouncements

**Second Quarter 2007 Highlights**

Our financial and operating results for the quarter ended June 30, 2007 included the following:

- During the second quarter of 2007, our oil and natural gas revenues were $180.7 million. This represents a 37 percent increase over the $131.8 million of oil and natural gas revenues reported in the second quarter of 2006. Our revenues increased as a result of increased production volumes and higher realized average prices.

- Our realized average oil price for the second quarter of 2007, including the effects of commodity derivative contracts, increased $0.93 per Bbl to $51.92 per Bbl as compared to $50.99 per Bbl in the second quarter of 2006. Our realized average natural gas price for the second quarter of 2007, including the effects of commodity derivative contracts, decreased $0.06 per Mcf to $6.52 per Mcf as compared to $6.58 per Mcf in the second quarter of 2006.

- Production volumes for the second quarter of 2007 increased to 41,384 BOE/D as compared to 30,867 BOE/D for the second quarter of 2006. The rise in production volumes was primarily attributable to our Big Horn Basin and Williston Basin acquisitions and our development programs. Oil represented 69 percent and 65 percent of our total production volumes in the second quarter of 2007 and 2006, respectively.

- We reported net income of $15.2 million, or $0.28 per diluted share, in the second quarter of 2007, as compared to net income of $22.2 million, or $0.42 per diluted share, for the second quarter of 2006. The decrease in net income was primarily due to pretax increases in interest expense of $17.1 million as a result of higher debt levels used to fund the

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**ENCORE ACQUISITION COMPANY**

Big Horn Basin and Williston Basin acquisitions and in depletion, depreciation, and amortization ( DD&A ) of $24.3 million as a result of higher rates associated with these acquisitions.

We invested $480.5 million in oil and natural gas activities during the second quarter of 2007 (excluding related asset retirement obligations of $0.2 million). Of this amount, we invested $94.0 million in development, exploitation, HPAI expansion, and exploration activities, which yielded 51 gross (16.7 net) productive wells, and $386.4 million in acquisitions, primarily related to the Williston Basin acquisition. We operated between 10 and 12 drilling rigs during the second quarter of 2007, including 4 to 5 rigs related to our West Texas joint development agreement.

On January 23, 2007, we entered into a purchase and sale agreement with certain subsidiaries of Anadarko to acquire oil and natural gas properties and related assets in the Williston Basin of Montana and North Dakota. The closing of the Williston Basin acquisition occurred on April 11, 2007. The purchase price for the Williston Basin assets was approximately $393.7 million, including transaction costs of approximately $1.2 million.

On June 29, 2007, we completed the sale of certain oil and natural gas properties in the Mid-Continent for net proceeds of approximately $293.6 million and recorded a loss on sale of $2.3 million. Subsequent to June 30, 2007, additional Mid-Continent properties that were subject to exercises of preferential rights were sold for net cash proceeds of $5.5 million. Proceeds from the Mid-Continent disposition were used to reduce outstanding borrowings under our revolving credit facilities.

## Results of Operations

### Comparison of Quarter Ended June 30, 2007 to Quarter Ended June 30, 2006

***Oil and natural gas revenues and production.*** The following table illustrates the primary components of oil and natural gas revenues for the three months ended June 30, 2007 and 2006, as well as each quarter s respective oil and natural gas production volumes:

**ENCORE ACQUISITION COMPANY**

| | Three months ended June 30, 2007 | Three months ended June 30, 2006 | *Increase / (Decrease)* | |
|---|---|---|---|---|
| | (in thousands, except per unit and per day amounts) | | | |
| **Revenues:** | | | | |
| Oil wellhead | $ 146,420 | $ 105,765 | *$ 40,655* | |
| Oil hedges | (10,824) | (13,331) | *2,507* | |
| Total oil revenues | $ 135,596 | $ 92,434 | *$ 43,162* | *47%* |
| Natural gas wellhead | $ 47,704 | $ 40,758 | *$ 6,946* | |
| Natural gas hedges | (2,573) | (1,415) | *(1,158)* | |
| Total natural gas revenues | $ 45,131 | $ 39,343 | *$ 5,788* | *15%* |
| Combined wellhead | $ 194,124 | $ 146,523 | *$ 47,601* | |
| Combined hedges | (13,397) | (14,746) | *1,349* | |
| Total combined oil and natural gas revenues | $ 180,727 | $ 131,777 | *$ 48,950* | *37%* |
| **Revenues:** | | | | |
| Oil wellhead ($/Bbl) | $ 56.07 | $ 58.34 | *$ (2.27)* | |
| Oil hedges ($/Bbl) | (4.15) | (7.35) | *3.20* | |
| Total oil revenues ($/Bbl) | $ 51.92 | $ 50.99 | *$ 0.93* | *2%* |
| Natural gas wellhead ($/Mcf) | $ 6.89 | $ 6.82 | *$ 0.07* | |
| Natural gas hedges ($/Mcf) | (0.37) | (0.24) | *(0.13)* | |
| Total natural gas revenues ($/Mcf) | $ 6.52 | $ 6.58 | *$ (0.06)* | *-1%* |
| Combined wellhead ($/BOE) | $ 51.55 | $ 52.16 | *$ (0.61)* | |
| Combined hedges ($/BOE) | (3.56) | (5.25) | *1.69* | |
| Total combined oil and natural gas revenues ($/BOE) | $ 47.99 | $ 46.91 | *$ 1.08* | *2%* |
| **Total production volumes:** | | | | |
| Oil (Bbls) | 2,611 | 1,813 | *798* | *44%* |
| Natural gas (Mcf) | 6,927 | 5,977 | *950* | *16%* |

| | | | | |
|---|---|---|---|---|
| Combined (BOE) | 3,766 | 2,809 | *957* | *34%* |
| | | | | |
| **Daily production volumes:** | | | | |
| Oil (Bbls/D) | 28,696 | 19,920 | *8,776* | *44%* |
| Natural gas (Mcf/D) | 76,123 | 65,682 | *10,441* | *16%* |
| Combined (BOE/D) | 41,384 | 30,867 | *10,517* | *34%* |
| | | | | |
| **Average NYMEX prices:** | | | | |
| Oil (per Bbl) | $ 65.03 | $ 70.70 | *$ (5.67)* | *-8%* |
| Natural gas (per Mcf) | $ 7.66 | $ 6.65 | *$ 1.01* | *15%* |

Oil revenues increased $43.2 million from $92.4 million in the second quarter of 2006 to $135.6 million in the second quarter of 2007. The increase is primarily due to an increase in oil production volumes of 798 MBbls, which contributed approximately $46.6 million in additional oil revenues. The increase in oil production volumes is primarily the result of our Big Horn Basin and Williston Basin acquisitions and our development programs. Due to a decrease in commodity derivative contract costs included in oil revenues, our average realized oil price increased $0.93 per Bbl despite the decrease in our wellhead price. Our lower average oil wellhead price resulted in a decrease of $5.9 million in oil revenues, or $2.27 per Bbl, while commodity derivative contract costs decreased $2.5 million, or $3.20 per Bbl. Our average oil wellhead price decreased $2.27 per Bbl in the second quarter of 2007 over the second quarter of 2006 as a result of decreases in the overall market price for oil as reflected in the decrease in the average NYMEX price from $70.70 per Bbl in the second quarter of 2006 to $65.03 per Bbl in the second quarter of 2007. Our oil production volumes would have been 27,809 Bbls/D and 19,431 Bbls/D for the three months ended June 30, 2007 and 2006, respectively, excluding volumes associated with our Mid-Continent disposition.

Our oil wellhead revenue was reduced by $6.1 million and $6.6 million in the three months ended June 30, 2007 and 2006, respectively, for the net profits interests payments related to our CCA properties.

Natural gas revenues increased $5.8 million from $39.3 million in the second quarter of 2006 to $45.1 million in the second quarter of 2007. The increase is primarily due to an increase in production volumes of 950 Mcf, which contributed approximately $6.5 million in additional natural gas revenues. The increase in natural gas production volumes is the result of our development programs on the West Texas joint development agreement with ExxonMobil and in the Mid-Continent area. Due to an increase in commodity derivative contract costs included in natural gas revenues, our average realized natural gas price decreased $0.06 per Mcf despite the increase in our wellhead price. Our higher average natural gas wellhead price resulted in an increase of $0.5 million in natural gas revenues, or $0.07 per Mcf, while commodity derivative contract costs increased $1.2 million, or $0.13 per Mcf. Our average natural gas wellhead price increased $0.07 per Mcf in the second quarter of 2007 over the second quarter of 2006 as a result of increases in the overall market price for natural gas as reflected in the increase in the average NYMEX price from $6.65 per Mcf in the second quarter of 2006 to $7.66 per Mcf in the second quarter of 2007. Our natural gas production volumes would have been 54,196 Mcf/D and 49,383 Mcf/D for the three months ended June 30, 2007 and 2006, respectively, excluding volumes associated with our Mid-Continent disposition.

The table below illustrates the relationship between oil and natural gas wellhead prices as a percentage of average NYMEX prices for the three months ended June 30, 2007 and 2006. Management uses the wellhead to NYMEX margin analysis to analyze trends in our oil and natural gas revenues.

| | Three months ended June 30, | |
|---|---|---|
| | **2007** | **2006** |
| Oil wellhead ($/Bbl) | $56.07 | $ 58.34 |
| Average NYMEX ($/Bbl) | $65.03 | $ 70.70 |
| Differential to NYMEX | $ (8.96) | $(12.36) |
| Oil wellhead to NYMEX percentage | 86% | 83% |
| | | |
| Natural gas wellhead ($/Mcf) | $ 6.89 | $ 6.82 |
| Average NYMEX ($/Mcf) | $ 7.66 | $ 6.65 |
| Differential to NYMEX | $ (0.77) | $ 0.17 |
| Natural gas wellhead to NYMEX percentage | 90% | 103% |

In the second quarter of 2007, our oil wellhead price as a percentage of the average NYMEX price increased to 86 percent from 83 percent in the second quarter of 2006. The differential was due to market conditions in the Rocky Mountain refining area, which has adversely affected the oil wellhead price we receive on our CCA and Williston Basin production. Production increases from competing Canadian and Rocky Mountain producers, in conjunction with limited refining and pipeline capacity in the Rocky Mountain area, created steep pricing discounts in the second quarter of 2006, but have since tightened. The oil differential in the second quarter of 2007 negatively impacted oil revenues by approximately $23.4 million as compared to approximately $22.4 million in the second quarter of 2006. We expect our oil wellhead differentials to remain approximately constant or to widen slightly in the third quarter of 2007 as compared to the second quarter of 2007.

In the second quarter of 2007, our natural gas wellhead price as a percentage of the average NYMEX price fell to 90 percent from 103 percent in the second quarter of 2006. The differential widened because the price received for natural gas in CCA did not correlate well with NYMEX during the quarter due to market conditions in the Rockies. The natural gas differential in the second quarter of 2007 negatively impacted natural gas revenues by approximately $5.3 million as compared with a favorable impact of approximately $1.0 million in the second quarter of 2006. We expect our natural gas wellhead differentials to remain approximately constant or to widen slightly in the third quarter of 2007 as compared to the second quarter of 2007.

***Marketing revenues and expenses.*** In 2006, we began purchasing third-party oil Bbls from a counterparty other than to whom the Bbls were sold for aggregation and sale with our own equity production in various markets. These purchases are for strategic purposes to assist us in marketing our production by decreasing our dependence on individual markets. These activities allow us to aggregate larger volumes, facilitate our efforts to maximize the prices we receive for production, provide for a greater allocation of future pipeline capacity in the event of curtailments, and enable us to reach other markets.

In March 2007, we acquired a gas pipeline from Anadarko as part of the Big Horn Basin acquisition for which natural gas volumes are purchased from one counterparty at the inlet to the pipeline and sold to another counterparty at the end of the pipeline.

The following table summarizes our marketing activities for the three months ended June 30, 2007 and 2006:

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| | Three months ended June 30, 2007 | 2006 |
|---|---|---|
| | (in thousands, except per BOE amounts) | |
| Marketing revenues | $ 8,916 | $ 25,716 |
| Marketing expenses | (8,507) | (24,914) |
| Marketing, net | $ 409 | $ 802 |
| Marketing revenues per BOE | $ 2.37 | $ 9.16 |
| Marketing expenses per BOE | (2.26) | (8.87) |
| Marketing, net per BOE | $ 0.11 | $ 0.29 |

***Expenses.*** The following table summarizes our expenses, excluding marketing expenses shown above, for the three months ended June 30, 2007 and 2006:

| | Three months ended June 30, 2007 | 2006 | *Increase / (Decrease)* | |
|---|---|---|---|---|
| **Expenses (in thousands):** | | | | |
| Production: | | | | |
| Lease operations | $ 37,552 | $ 23,118 | *$ 14,434* | |
| Production, ad valorem, and severance taxes | 19,232 | 12,580 | *6,652* | |
| Total production expenses | 56,784 | 35,698 | *21,086* | *59%* |
| Other: | | | | |
| Depletion, depreciation, and amortization | 52,318 | 27,988 | *24,330* | |
| Exploration | 3,415 | 4,016 | *(601)* | |
| General and administrative | 6,188 | 5,421 | *767* | |
| Derivative fair value loss | 6,766 | 10,794 | *(4,028)* | |
| Other operating | 4,751 | 1,068 | *3,683* | |
| Total operating | 130,222 | 84,985 | *45,237* | *53%* |
| Interest | 27,820 | 10,718 | *17,102* | |
| Income tax provision | 8,524 | 15,069 | *(6,545)* | |
| Total expenses | $ 166,566 | $ 110,772 | *$ 55,794* | *50%* |

**Expenses (per BOE):**

| | | | | |
|---|---|---|---|---|
| Production: | | | | |
| Lease operations | $ 9.97 | $ 8.23 | *$ 1.74* | |
| Production, ad valorem, and severance taxes | 5.11 | 4.48 | *0.63* | |
| Total production expenses | 15.08 | 12.71 | *2.37* | *19%* |
| Other: | | | | |
| Depletion, depreciation, and amortization | 13.89 | 9.96 | *3.93* | |
| Exploration | 0.91 | 1.43 | *(0.52)* | |
| General and administrative | 1.64 | 1.93 | *(0.29)* | |
| Derivative fair value loss | 1.80 | 3.84 | *(2.04)* | |
| Other operating | 1.26 | 0.38 | *0.88* | |
| Total operating | 34.58 | 30.25 | *4.33* | *14%* |
| Interest | 7.39 | 3.82 | *3.57* | |
| Income tax provision | 2.26 | 5.36 | *(3.10)* | |
| Total expenses | $ 44.23 | $ 39.43 | *$ 4.80* | *12%* |

***Production expenses.*** Total production expenses increased $21.1 million from $35.7 million in the second quarter of 2006 to $56.8 million in the second quarter of 2007. This increase resulted from an increase in total production volumes, as well as a

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$2.37 increase in production expenses per BOE. Our production margin (defined as oil and natural gas revenues less production expenses) for the second quarter of 2007 increased by 29 percent ($27.9 million) as compared to the second quarter of 2006. Total production expenses per BOE increased by 19 percent while total oil and natural gas revenues per BOE increased by only two percent. On a per BOE basis, our production margin decreased four percent to $32.91 per BOE as compared to $34.20 per BOE for the second quarter of 2006.

The production expense attributable to lease operations expense ( LOE ) increased $14.4 million from $23.1 million in the second quarter of 2006 to $37.6 million in the second quarter of 2007, primarily as a result of an increase in production volumes, which contributed approximately $7.9 million of additional LOE, and an increase in the average per BOE rate, which contributed approximately $6.6 million of additional LOE. The increase in production volumes is the result of our Big Horn Basin and Williston Basin acquisitions. The increase in our average LOE per BOE rate of $1.74 was attributable to:

increases in prices paid to oilfield service companies and suppliers due to a current higher price environment;

increased operational activity to maximize production;

HPAI expensed at the CCA; and

higher salary levels for engineers and other technical professionals.

The production expense attributable to production, ad valorem, and severance taxes ( production taxes ) increased $6.7 million from $12.6 million in the second quarter of 2006 to $19.2 million in the second quarter of 2007. The increase is due to higher wellhead revenues. As a percentage of oil and natural gas revenues (excluding the effects of commodity derivative contracts), production taxes increased to 9.9 percent in the second quarter of 2007 as compared to 8.6 percent in the second quarter of 2006 as a result of higher rates in the states where the properties associated with the Williston Basin acquisition are located. The effect of commodity derivative contracts is excluded from oil and natural gas revenues in the calculation of these percentages because this method more closely reflects the method used to calculate actual production taxes paid to taxing authorities.

***DD&A expense.*** DD&A expense increased $24.3 million from $28.0 million in the second quarter of 2006 to $52.3 million in the second quarter of 2007 due to a higher per BOE rate and increased production volumes. The per BOE rate in the second quarter of 2007 increased $3.93 as compared to the second quarter of 2006 due to the higher cost basis of our recently acquired Big Horn Basin and Williston Basin properties, development of proved undeveloped reserves and higher finding, development, and acquisition costs resulting from increases in rig rates, oilfield services costs, and acquisition costs. These factors resulted in additional DD&A expense of approximately $14.8 million. The increase in production volumes resulted in approximately $9.5 million of additional DD&A expense.

***Exploration expense.*** Exploration expense decreased $0.6 million in the second quarter of 2007 as compared to the second quarter of 2006. During the second quarter of 2007, we did not expense any exploratory dry holes. During the second quarter of 2006, we expensed 5 exploratory dry holes totaling $2.0 million. In addition, impairment of unproved acreage in the second quarter of 2007 increased $1.6 million as compared to the second quarter of 2006 as we added additional leasehold costs and refined our estimated success rate in certain areas. The following table details our exploration-related expenses for the three months ended June 30, 2007 and 2006:

| | **Three months ended June 30,** | | ***Increase / (Decrease)*** |
|---|---|---|---|
| | **2007** | **2006** | |
| | (in thousands) | | |
| Dry holes | $ 539 | $ 1,998 | *$ (1,459)* |
| Geological and seismic | 94 | 847 | *(753)* |
| Delay rentals | 163 | 129 | *34* |

| | | | |
|---|---|---|---|
| Impairment of unproved acreage | 2,619 | 1,042 | *1,577* |
| Total | $ 3,415 | $ 4,016 | *$ (601)* |

***G&A expense.*** G&A expense increased $0.8 million from $5.4 million in the second quarter of 2006 to $6.2 million in the second quarter of 2007. The overall increase is primarily the result of increased staffing to manage our larger asset base, higher activity levels, and increased personnel costs due to intense competition for human resources within the industry.

***Derivative fair value loss.*** To increase clarity in our fina ncial statements by accounting for all contracts under the same method, we elected to discontinue hedge accounting prospectively for all of our remaining commodity derivatives beginning in

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July 2006. While this change has no effect on our cash flows, results of operations are affected by mark-to-market gains and losses, which fluctuate with the changes in oil and natural gas prices.

During the second quarter of 2007, we recorded a $6.8 million derivative fair value loss as compared to $10.8 million in the second quarter of 2006, the components of which were as follows:

| | Three months ended June 30, 2007 | 2006 | Increase / (Decrease) |
|---|---|---|---|
| | (in thousands) | | |
| Ineffectiveness on designated cash flow hedges | $ | $ (1,091) | *$ 1,091* |
| Mark-to-market loss on undesignated derivative contracts | 10,315 | 12,368 | *(2,053)* |
| Settlements on commodity contracts | (3,549) | (483) | *(3,066)* |
| Total derivative fair value loss | $ 6,766 | $ 10,794 | *$ (4,028)* |

***Other operating expense.*** Other operating expense increased $3.7 million from $1.1 million in the second quarter of 2006 to $4.8 million in the second quarter of 2007. The increase is primarily due to a $2.3 million loss on the sale of the Mid-Continent properties and increases in third-party transportation costs attributable to moving our CCA production into markets outside the immediate area of the production.

***Interest expense.*** Interest expense increased $17.1 million in the second quarter of 2007 as compared to the second quarter of 2006. The increase is primarily due to additional debt used to finance the Big Horn Basin and Williston Basin acquisitions. The weighted average interest rate for all long-term debt for the second quarter of 2007 was 7.0 percent as compared to 7.1 percent for the second quarter of 2006.

The following table illustrates the components of interest expense for the three months ended June 30, 2007 and 2006:

| | Three months ended June 30, 2007 | 2006 | Increase / (Decrease) |
|---|---|---|---|
| | (in thousands) | | |
| 6 1/4% Notes | $ 2,425 | $ 2,420 | *$ 5* |
| 6% Notes | 4,627 | 4,620 | *7* |
| 7 1/4% Notes | 2,747 | 2,748 | *(1)* |
| Revolving credit facilities | 17,396 | 488 | *16,908* |
| Other | 625 | 442 | *183* |
| Total | $ 27,820 | $ 10,718 | *$ 17,102* |

***Income taxes.*** During the second quarter of 2007, we recorded an income tax provision of $8.5 million as compared to $15.1 million in the second quarter of 2006. Our effective tax rate decreased in the second quarter of 2007 to 36.0 percent from 40.4 percent in the second quarter of 2006 due to a 2007 change in the apportionment of state net deferred tax liabilities and the 2006 enactment of a Texas franchise tax reform measure. The disposition of oil and natural gas properties in the Mid-Continent during the second quarter of 2007 resulted in a revaluation of state net deferred tax liabilities due to a larger apportionment of future taxable income to states with lower tax rates. The expense related to the state net deferred liability adjustment decreased the current quarter s tax provision for the second quarter of 2007 by $0.4 million.

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**Comparison of Six Months Ended June 30, 2007 to Six Months Ended June 30, 2006**

***Oil and natural gas revenues and production.*** The following table illustrates the primary components of oil and natural gas revenues for the six months ended June 30, 2007 and 2006, as well as each period s respective oil and natural gas production volumes:

| | Six months ended June 30, 2007 | 2006 | *Increase / (Decrease)* | |
|---|---|---|---|---|
| | (in thousands, except per unit and per day amounts) | | | |
| **Revenues:** | | | | |
| Oil wellhead | $ 239,867 | $ 193,873 | *$ 45,994* | |
| Oil hedges | (21,648) | (25,324) | *3,676* | |
| Total oil revenues | $ 218,219 | $ 168,549 | *$ 49,670* | *29%* |
| Natural gas wellhead | $ 83,255 | $ 82,804 | *$ 451* | |
| Natural gas hedges | (5,146) | (5,931) | *785* | |
| Total natural gas revenues | $ 78,109 | $ 76,873 | *$ 1,236* | *2%* |
| Combined wellhead | $ 323,122 | $ 276,677 | *$ 46,445* | |
| Combined hedges | (26,794) | (31,255) | *4,461* | |
| Total combined oil and natural gas revenues | $ 296,328 | $ 245,422 | *$ 50,906* | *21%* |
| **Revenues:** | | | | |
| Oil wellhead ($/Bbl) | $ 53.10 | $ 52.71 | *$ 0.39* | |
| Oil hedges ($/Bbl) | (4.79) | (6.89) | *2.10* | |
| Total oil revenues ($/Bbl) | $ 48.31 | $ 45.82 | *$ 2.49* | *5%* |
| Natural gas wellhead ($/Mcf) | $ 6.39 | $ 6.85 | *$ (0.46)* | |
| Natural gas hedges ($/Mcf) | (0.39) | (0.49) | *0.10* | |
| Total natural gas revenues ($/Mcf) | $ 6.00 | $ 6.36 | *$ (0.36)* | *-6%* |
| Combined wellhead ($/BOE) | $ 48.30 | $ 48.61 | *$ (0.31)* | |
| Combined hedges ($/BOE) | (4.01) | (5.49) | *1.48* | |
| Total combined oil and natural gas revenues ($/BOE) | $ 44.29 | $ 43.12 | *$ 1.17* | *3%* |

| | | | | |
|---|---|---|---|---|
| **Total production volumes:** | | | | |
| Oil (Bbls) | 4,517 | 3,678 | *839* | *23%* |
| Natural gas (Mcf) | 13,036 | 12,084 | *952* | *8%* |
| Combined (BOE) | 6,690 | 5,692 | *998* | *18%* |
| | | | | |
| **Daily production volumes:** | | | | |
| Oil (Bbls/D) | 24,957 | 20,319 | *4,638* | *23%* |
| Natural gas (Mcf/D) | 72,022 | 66,765 | *5,257* | *8%* |
| Combined (BOE/D) | 36,961 | 31,447 | *5,514* | *18%* |
| | | | | |
| **Average NYMEX prices:** | | | | |
| Oil (per Bbl) | $ 61.65 | $ 67.09 | *$ (5.44)* | *-8%* |
| Natural gas (per Mcf) | $ 7.42 | $ 7.28 | *$ 0.14* | *2%* |

Oil revenues increased $49.7 million from $168.5 million in the first six months of 2006 to $218.2 million in the first six months of 2007. The increase is primarily due to an increase in oil production volumes of 839 MBbls, which contributed approximately $44.3 million in additional oil revenues, and higher average realized oil prices, which contributed approximately $5.4 million in additional oil revenues. The increase in oil production volumes is primarily the result of our Big Horn Basin and Williston Basin acquisitions and our development programs. Our realized average oil price increased as our wellhead price increased and commodity derivative contract costs included in oil revenues decreased. Our higher average oil wellhead price resulted in $1.7 million of additional oil revenues, or $0.39 per Bbl, and commodity derivative contract costs decreased $3.7 million, or $2.10 per Bbl. Our average oil wellhead price increased $0.39 per Bbl in the first six months of 2007 over the first six months of 2006 as a result of the tightening of our oil differential. Our oil production volumes would have been 24,182 Bbls/D and 19,963 Bbls/D for the six months ended June 30, 2007 and 2006, respectively, excluding volumes associated with our Mid-Continent disposition.

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Our oil wellhead revenue was reduced by $10.2 million and $12.2 million in the six months ended June 30, 2007 and 2006, respectively, for the net profits interests payments related to our CCA properties.

Natural gas revenues increased $1.2 million from $76.9 million for the six months ended June 30, 2006 to $78.1 million for the six months ended June 30, 2007. The increase is primarily due to an increase in production volumes of 952 Mcf, which contributed approximately $6.5 million in additional natural gas revenues, partially offset by lower average realized natural gas prices, which reduced revenues by approximately $5.3 million. The increase in natural gas production volumes is the result of our West Texas joint development program with ExxonMobil and our development program in the Mid-Continent area. Due to a decrease in our natural gas wellhead price, our realized average natural gas price decreased $0.36 per Mcf despite a decrease in commodity derivative contract costs included in natural gas revenues. Our lower average natural gas wellhead price resulted in a decrease of $6.1 million in natural gas revenues, or $0.46 per Mcf, while commodity derivative contract costs decreased $0.8 million, or $0.10 per Mcf. Our average natural gas wellhead price decreased $0.46 per Mcf in the first six months of 2007 over the first six months of 2006 as a result of a widening of our natural gas differential. Our natural gas production volumes would have been 51,201 Mcf/D and 50,315 Mcf/D for the six months ended June 30, 2007 and 2006, respectively, excluding volumes associated with our Mid-Continent disposition.

The table below illustrates the relationship between oil and natural gas wellhead prices as a percentage of average NYMEX prices for the six months ended June 30, 2007 and 2006. Management uses the wellhead to NYMEX margin analysis to analyze trends in our oil and natural gas revenues.

| | Six months ended June 30, | |
|---|---|---|
| | **2007** | **2006** |
| Oil wellhead ($/Bbl) | $ 53.10 | $ 52.71 |
| Average NYMEX ($/Bbl) | $ 61.65 | $ 67.09 |
| Differential to NYMEX | $ (8.55) | $ (14.38) |
| Oil wellhead to NYMEX percentage | 86% | 79% |
| | | |
| Natural gas wellhead ($/Mcf) | $ 6.39 | $ 6.85 |
| Average NYMEX ($/Mcf) | $ 7.42 | $ 7.28 |
| Differential to NYMEX | $ (1.03) | $ (0.43) |
| Natural gas wellhead to NYMEX percentage | 86% | 94% |

In the first six months of 2007, our oil wellhead price as a percentage of the average NYMEX price increased to 86 percent from 79 percent in the first six months of 2006. The differential was due to market conditions in the Rocky Mountain refining area, which has adversely affected the oil wellhead price we receive on our CCA and Williston Basin production. Production increases from competing Canadian and Rocky Mountain producers, in conjunction with limited refining and pipeline capacity in the Rocky Mountain area, created steep pricing discounts in the first six months of 2006, but have since tightened. The oil differential in the first six months of 2007 negatively impacted oil revenues by approximately $38.6 million as compared to approximately $52.9 million in the first six months of 2006.

In the first six months of 2007, our natural gas wellhead price as a percentage of the average NYMEX price decreased to 86 percent from 94 percent in the first six months of 2006. The differential widened because the price received for natural gas in CCA did not correlate well with NYMEX in the first six months of 2007 due to market conditions in the Rockies. The natural gas differential in the first six months of 2007 negatively impacted natural gas revenues by approximately $13.4 million as compared to approximately $5.2 million in the first six months of 2006.

***Marketing revenues and expenses.*** The following table summarizes our marketing activities for the six months ended June 30, 2007 and 2006:

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| | Six months ended June 30, 2007 | | Six months ended June 30, 2006 | |
|---|---|---|---|---|
| | (in thousands, except per BOE amounts) | | | |
| Marketing revenues | $ | 23,857 | $ | 60,032 |
| Marketing expenses | | (23,518) | | (57,660) |
| Marketing, net | $ | 339 | $ | 2,372 |
| Marketing revenues per BOE | $ | 3.57 | $ | 10.55 |
| Marketing expenses per BOE | | (3.52) | | (10.13) |
| Marketing, net per BOE | $ | 0.05 | $ | 0.42 |

***Expenses.*** The following table summarizes our expenses, excluding marketing expenses shown above, for the six months ended June 30, 2007 and 2006:

| | Six months ended June 30, 2007 | Six months ended June 30, 2006 | *Increase / (Decrease)* | |
|---|---|---|---|---|
| **Expenses (in thousands):** | | | | |
| Production: | | | | |
| Lease operations | $ 68,072 | $ 45,854 | *$ 22,218* | |
| Production, ad valorem, and severance taxes | 31,747 | 24,822 | *6,925* | |
| Total production expenses | 99,819 | 70,676 | *29,143* | *41%* |
| Other: | | | | |
| Depletion, depreciation, and amortization | 87,346 | 55,008 | *32,338* | |
| Exploration | 14,936 | 6,025 | *8,911* | |
| General and administrative | 13,548 | 11,949 | *1,599* | |
| Derivative fair value loss | 52,380 | 13,100 | *39,280* | |
| Other operating | 7,316 | 2,596 | *4,720* | |
| Total operating | 275,345 | 159,354 | *115,991* | *73%* |
| Interest | 44,107 | 22,505 | *21,602* | |
| Income tax provision (benefit) | (7,496) | 26,313 | *(33,809)* | |
| Total expenses | $ 311,956 | $ 208,172 | *$ 103,784* | *50%* |

**Expenses (per BOE):**

| | | | | |
|---|---|---|---|---|
| Production: | | | | |
| Lease operations | $ 10.18 | $ 8.06 | *$ 2.12* | |
| Production, ad valorem, and severance taxes | 4.75 | 4.36 | *0.39* | |
| Total production expenses | 14.93 | 12.42 | *2.51* | *20%* |
| Other: | | | | |
| Depletion, depreciation, and amortization | 13.06 | 9.66 | *3.40* | |
| Exploration | 2.23 | 1.06 | *1.17* | |
| General and administrative | 2.03 | 2.10 | *(0.07)* | |
| Derivative fair value loss | 7.83 | 2.30 | *5.53* | |
| Other operating | 1.09 | 0.46 | *0.63* | |
| Total operating | 41.17 | 28.00 | *13.17* | *47%* |
| Interest | 6.59 | 3.95 | *2.64* | |
| Income tax provision (benefit) | (1.12) | 4.62 | *(5.74)* | |
| Total expenses | $ 46.64 | $ 36.57 | *$ 10.07* | *28%* |

***Production expenses.*** Total production expenses increased $29.1 million from $70.7 million in the first six months of 2006 to $99.8 million in the first six months of 2007. This increase resulted from an increase in total production volumes, as well as a

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$2.51 increase in production expenses per BOE. Our production margin for the first six months of 2007 increased by 12 percent ($21.8 million) as compared to the first six months of 2006. Total production expenses per BOE increased by 20 percent while total oil and natural gas revenues per BOE increased by only three percent. On a per BOE basis, our production margin decreased four percent to $29.36 per BOE as compared to $30.70 per BOE for the first six months of 2006.

The production expense attributable to LOE increased $22.2 million from $45.9 million in the first six months of 2006 to $68.1 million in the first six months of 2007, primarily as a result of an increase in the average per BOE rate, which contributed approximately $14.2 million of additional LOE, and an increase in production volumes, which contributed approximately $8.0 million of additional LOE. The increase in production volumes is the result of our Big Horn Basin and Williston Basin acquisitions. The increase in our average LOE per BOE rate of $2.12 was attributable to:

- increases in prices paid to oilfield service companies and suppliers due to a current higher price environment;
- increased operational activity to maximize production;
- HPAI expensed at the CCA; and
- higher salary levels for engineers and other technical professionals.

The production expense attributable to production taxes increased $6.9 million from $24.8 million for the six months ended June 30, 2006 to $31.7 million for the six months ended June 30, 2007. The increase is due to higher wellhead revenues. As a percentage of oil and natural gas revenues (excluding the effects of commodity derivative contracts), production taxes increased to 9.8 percent in the first six months of 2007 as compared to 9.0 percent in the first six months of 2006 as a result of higher rates in the states where the properties associated with the Big Horn Basin and Williston Basin acquisitions are located.

***DD&A expense.*** DD&A expense increased $32.3 million from $55.0 million for the six months ended June 30, 2006 to $87.3 million for the six months ended June 30, 2007 due to a higher per BOE rate and increased production volumes. The per BOE rate in the first six months of 2007 increased $3.40 as compared to the first six months of 2006 due to the higher cost basis of our recently acquired Big Horn Basin and Williston Basin properties, development of proved undeveloped reserves and higher finding, development, and acquisition costs resulting from increases in rig rates, oilfield services costs, and acquisition costs. These factors resulted in additional DD&A expense of approximately $22.7 million. The increase in production volumes resulted in approximately $9.6 million of additional DD&A expense.

***Exploration expense.*** Exploration expense increased $8.9 million in the first six months of 2007 as compared to the first six months of 2006. During the first six months of 2007, we expensed 3 exploratory dry holes totaling $9.0 million. During the first six months of 2006, we expensed 7 exploratory dry holes totaling $2.6 million. In addition, impairment of unproved acreage in the first six months of 2007 increased $3.0 million as compared to the first six months of 2006 as we added additional leasehold costs and refined our estimated success rate in certain areas. The following table details our exploration-related expenses for the six months ended June 30, 2007 and 2006:

| | Six months ended June 30, 2007 | Six months ended June 30, 2006 | *Increase / (Decrease)* |
|---|---|---|---|
| | | (in thousands) | |
| Dry holes | $ 9,020 | $ 2,580 | *$ 6,440* |
| Geological and seismic | 725 | 1,252 | *(527)* |
| Delay rentals | 341 | 355 | *(14)* |
| Impairment of unproved acreage | 4,850 | 1,838 | *3,012* |

| | | | |
|---|---|---|---|
| Total | $ 14,936 | $ 6,025 | *$ 8,911* |

***G&A expense.*** G&A expense increased $1.6 million from $11.9 million in the first six months of 2006 to $13.5 million in the first six months of 2007. The overall increase is primarily the result of increased staffing to manage our larger asset base, higher activity levels, and increased personnel costs due to intense competition for human resources within the industry.

***Derivative fair value loss.*** During the six months ended June 30, 2007, we recorded a $52.4 million derivative fair value loss as compared to $13.1 million in the six months ended June 30, 2006, the components of which were as follows:

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| | Six months ended June 30, 2007 | 2006 | Increase / (Decrease) |
|---|---|---|---|
| | (in thousands) | | |
| Ineffectiveness on designated cash flow hedges | $ | $ 1,748 | $ (1,748) |
| Mark-to-market loss on undesignated derivative contracts | 64,125 | 13,461 | 50,664 |
| Settlements on commodity contracts | (11,745) | (2,109) | (9,636) |
| Total derivative fair value loss | $ 52,380 | $ 13,100 | $ 39,280 |

***Other operating expense.*** Other operating expense increased $4.7 million from $2.6 million in the first six months of 2006 to $7.3 million in the first six months of 2007. The increase is primarily due to a $2.3 million loss on the sale of the Mid-Continent properties and increases in third-party transportation costs attributable to moving our CCA production into markets outside the immediate area of the production.

***Interest expense.*** Interest expense increased $21.6 million in the first six months of 2007 as compared to the first six months of 2006. The increase is primarily due to additional debt used to finance the Big Horn Basin and Williston Basin acquisitions. The weighted average interest rate for all long-term debt for the first six months of 2007 was 7.0 percent as compared to 7.1 percent for the same period of 2006.

The following table illustrates the components of interest expense for the six months ended June 30, 2007 and 2006:

| | Six months ended June 30, 2007 | 2006 | Increase / (Decrease) |
|---|---|---|---|
| | (in thousands) | | |
| 6 1/4% Notes | $ 4,850 | $ 4,840 | $ 10 |
| 6% Notes | 9,255 | 9,171 | 84 |
| 7 1/4% Notes | 5,493 | 5,493 | |
| Revolving credit facilities | 23,022 | 2,223 | 20,799 |
| Other | 1,487 | 778 | 709 |
| Total | $ 44,107 | $ 22,505 | $ 21,602 |

***Income taxes.*** During the first six months of 2007, we recorded an income tax benefit of $7.5 million, or an effective rate of 34.5 percent, as compared to an income tax provision of $26.3 million, or an effective rate of 39.6 percent, for the same period of 2006. This is due to a pre-tax loss in the first six months of 2007 as compared to pre-tax income in the first six months of 2006. The decrease in the effective rate is due to a 2007 change in the apportionment of state net deferred tax liabilities and the 2006 enactment of a Texas franchise tax reform measure. Asset acquisitions and dispositions in the first six months of 2007 resulted in a revaluation of state net deferred tax liabilities due to a larger apportionment of future taxable income to states with higher tax rates. The expense related to the state net deferred liability adjustment reduced the benefit resulting from the pre-tax loss for the six months ended June 30, 2007 by $0.5 million. Our estimated annual effective tax rate was 39.5 percent for the six months ended June 30, 2007.

On January 1, 2007, we adopted the provisions of FIN 48. FIN 48 clarifies the accounting for uncertainty in income taxes recognized in a company s financial statements in accordance with SFAS 109. FIN 48 prescribes a recognition threshold and measurement attribute for the financial statement recognition and measurement of a tax position taken or expected to be taken in a tax return. We have performed an evaluation of tax positions and have determined that the adoption of FIN 48 did not have a material impact on our financial condition, results of operations, or cash flows.

**Capital Resources**

Our primary capital resources are as follows:

- Cash flows from operating activities;
- Cash flows from financing activities; and
- Current capitalization.

***Cash flows from operating activities*.** Cash provided by operating activities decreased $50.2 million from $131.5 million for the first six months of 2006 to $81.3 million for the first six months of 2007. The decrease was primarily due to an increase in our net derivative liabilities as a result of increases in our commodity derivative positions and the forward price curve, and an increase in accounts receivable as a result of increased oil and natural gas sales, partially offset by an increase in our production margin.

***Cash flows from financing activities.*** Our cash flows from financing activities consist primarily of proceeds from and payments on long-term debt and net proceeds received from the sale of additional common stock. During the six months ended June 30, 2007, we received net cash of $624.0 million from financing activities, including net borrowings on our revolving credit facilities of $639 million.

We periodically draw on our revolving credit facilities to fund acquisitions and other capital commitments. Historically, we have repaid large balances on our revolving credit facilities with proceeds from the issuance of senior subordinated notes in order to extend the maturity date of the debt and fix the interest rate. Our total borrowings less repayments on our revolving credit facilities, as described above, resulted in a net increase in outstanding borrowings under our revolving credit facilities of $639 million from $68 million at December 31, 2006 to $707 million at June 30, 2007, primarily due to borrowings used to finance the Big Horn Basin and Williston Basin acquisitions partially offset with repayments from the net proceeds received from the Mid-Continent disposition.

During the six months ended June 30, 2006, we received net cash of $33.9 million from financing activities. This consisted primarily of net proceeds from the issuance of 4 million shares of common stock in April 2006, which was used to repay $80 million outstanding under our revolving credit facility.

***Current capitalization.*** At June 30, 2007, we had total assets of $2.7 billion and total capitalization was $2.1 billion, of which 39 percent was represented by stockholders equity and 61 percent by long-term debt. At December 31, 2006, we had total assets of $2.0 billion and total capitalization was $1.5 billion, of which 55 percent was represented by stockholders equity and 45 percent by long-term debt. The percentages of our capitalization represented by stockholders equity and long-term debt could vary in the future if debt is used to finance future capital projects or potential acquisitions.

**Capital Commitments**

Our primary needs for cash are as follows:

Cash flows from investing activities including:

- Development, exploitation, and exploration of existing oil and natural gas properties;
- Acquisitions of oil and natural gas properties and leasehold acreage;

Funding of necessary working capital; and

Contractual obligations.

***Cash flows from investing activities.*** Cash used in investing activities increased $534.7 million from $166.4 million in the first six months of 2006 to $701.1 million in the first six months of 2007. The increase was primarily due to a $763.7 million increase in amounts paid for the acquisition of oil and natural gas properties, primarily due to the Big Horn and Williston Basin acquisitions, partially offset by a $290.9 million increase in amounts received for the disposition of oil and natural gas properties, primarily due to the Mid-Continent disposition.

***Development, exploitation, and exploration of existing oil and natural gas properties.*** The following table summarizes our costs incurred (excluding asset retirement obligations) related to development, exploitation, and exploration activities during the three and six months ended June 30, 2007 and 2006:

| | Three months ended June 30, | | Six months ended June 30, | |
|---|---|---|---|---|
| | 2007 | 2006 | 2007 | 2006 |
| | (in thousands) | | | |
| Development and exploitation | $ 74,339 | $ 63,010 | $ 136,521 | $ 95,895 |
| Exploration | 19,005 | 16,909 | 50,223 | 38,633 |
| HPAI | 680 | 7,878 | 1,996 | 14,459 |

| | | | | |
|---|---|---|---|---|
| Total | $ 94,024 | $ 87,797 | $ 188,740 | $ 148,987 |

*Development and exploitation*. Our expenditures for development and exploitation investments primarily relate to drilling development and infill wells, workovers of existing wells, and field related facilities. Our development and exploitation capital

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for the three months ended June 30, 2007 included a total of 44 gross (13.5 net) successful wells and 1 gross (0.9 net) development dry holes. Our development and exploitation capital for the first half of 2007 included a total of 88 gross (36.0 net) successful wells and 2 gross and (1.4 net) development dry holes.

We currently have 8 operated rigs drilling on the onshore continental United States with 2 rigs in the Mid-Continent, 1 rig in the Northern region, 1 rig in the New Mexico region and 4 rigs in West Texas.

*Exploration*. Our expenditures for exploration investments primarily relate to drilling exploratory wells, seismic costs, delay rentals, and geological and geophysical costs. In the second quarter of 2007, our exploration capital yielded 7 gross (3.3 net) successful wells and no exploratory dry holes. During the six months ended June 30, 2007, our exploration capital yielded 28 gross (10.4 net) exploratory wells that were productive and 3 gross (1.5 net) exploratory dry holes.

*HPAI*. During the three months ended June 30, 2007 and 2006, we invested $0.7 million and $7.9 million on the HPAI programs in the Pennel, Coral Creek, and Little Beaver units of the CCA. For the six months ended June 30, 2007 and 2006, we invested $2.0 million and $14.5 million on the HPAI programs.

***Acquisitions of oil and natural gas properties and leasehold acreage.*** The following table summarizes our costs incurred (excluding asset retirement obligations) for oil and natural gas property acquisitions during the three and six months ended June 30, 2007 and 2006:

| | Three months ended June 30, | | Six months ended June 30, | |
|---|---|---|---|---|
| | 2007 | 2006 | 2007 | 2006 |
| | (in thousands) | | | |
| Acquisitions of proved property | $ 365,909 | $ 3,545 | $ 761,885 | $ 4,052 |
| Acquisitions of leasehold acreage | 20,528 | 4,683 | 23,783 | 11,865 |
| Total | $ 386,437 | $ 8,228 | $ 785,668 | $ 15,917 |

*Acquisitions*. On March 7, 2007, we acquired oil and natural gas properties in the Big Horn Basin for a purchase price of approximately $393.3 million, including $1.2 million of transaction costs, $392.4 million of which related to proved properties. On April 11, 2007, we acquired oil and natural gas properties in the Williston Basin for a purchase price of approximately $393.7 million, including $1.2 million of transaction costs, $380.0 million of which related to proved properties.

*Leasehold acreage costs*. During the three and six months ended June 30, 2007, our capital expenditures for leasehold acreage totaled $20.5 million and $23.8 million, respectively. Of these amounts, $16.1 million related to the Williston Basin acquisition and the remainder related to the acquisition of unproved acreage in various areas. During the three and six months ended June 30, 2006, our capital expenditures for leasehold acreage totaled $4.7 million and $11.9 million, respectively, all of which related to the acquisition of unproved acreage in various areas.

***Funding of necessary working capital.*** At June 30, 2007, our working capital (defined as total current assets less total current liabilities) was negative $10.3 million while at December 31, 2006 our working capital was negative $40.7 million, an improvement of $30.4 million. The improvement is primarily attributable to an increase in accounts receivable as a result of increased oil and natural gas sales.

For the remainder of 2007, we expect working capital to remain negative. Negative working capital is expected mainly due to fair values of our commodity derivative contracts (the settlements of which will be offset by cash flows from the sale of production mitigated against price risk under those contracts) and deferred commodity derivative contract premiums. We anticipate cash reserves to be close to zero because we intend to use any excess cash to fund capital obligations and pay down any outstanding borrowings under our revolving credit facilities. We do not plan to pay cash dividends in the foreseeable future. Our production volumes and the overall 2007 commodity prices and our related differentials for oil and natural gas will be the largest variables affecting working capital. Our operating cash flow is determined in large part by production volumes and commodity prices. Assuming moderate to high commodity prices and constant or increasing production volumes, our operating cash flow should remain positive in 2007.

The Board has approved a capital budget of approximately $370 million for 2007. The level of these and other future expenditures is largely discretionary, and the amount of funds devoted to any particular activity may increase or decrease

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significantly, depending on available opportunities, timing of projects, and market conditions. We plan to finance our ongoing expenditures using internally generated cash flow, cash on hand, and borrowings under our revolving credit facilities.

***Contractual obligations.*** The following table illustrates our contractual obligations and commercial commitments outstanding at June 30, 2007:

| **Contractual Obligations and Commitments** | **Total** | **2007** | **2008 - 2009** | **2010 - 2011** | **Thereafter** |
|---|---|---|---|---|---|
| | Payments Due by Period (in thousands) | | | | |
| 6 1/4% Notes (a) | $ 215,626 | $ 4,688 | $ 18,750 | $ 18,750 | $ 173,438 |
| 6% Notes (a) | 453,000 | 9,000 | 36,000 | 36,000 | 372,000 |
| 7 1/4% Notes (a) | 264,188 | 5,438 | 21,750 | 21,750 | 215,250 |
| Revolving credit facilities (a) | 944,391 | 25,435 | 101,739 | 101,739 | 715,478 |
| Derivative obligations (b) | 73,137 | 33,270 | 39,011 | 856 | |
| Development commitments (c) | 124,835 | 78,146 | 46,689 | | |
| Operating leases and commitments (d) | 15,157 | 1,344 | 5,347 | 4,569 | 3,897 |
| Asset retirement obligations (e) | 138,345 | 653 | 2,611 | 2,611 | 132,470 |
| Total | $ 2,228,679 | $ 157,974 | $ 271,897 | $ 186,275 | $ 1,612,533 |

(a) Amounts included in the table above include both principal and projected interest payments. Please read Note 8 of Notes to Consolidated Financial Statements included in Item 1. Financial Statements for additional information regarding our long-term debt.

(b) Derivative obligations represent net liabilities for derivatives that were valued as of June 30, 2007. With the exception of $50.4 million of deferred premiums on derivative contracts, the ultimate settlement amounts of the remaining portions of our derivative obligations are unknown because they are subject to continuing market risk. Please read Item 3. Quantitative and Qualitative Disclosures about Market Risk and Note 6 of Notes to Consolidated Financial Statements included in Item 1. Financial Statements for additional information regarding our derivative obligations.

(c) Development commitments include: authorized purchases for work in process of

$41.2 million; future minimum payments for drilling rig operations of $76.6 million; and $7.0 million for minimum capital obligations associated with the remaining 7 commitment wells to be drilled under the ExxonMobil joint development agreement. Also at June 30, 2007, we had $111.1 million of authorized purchases not placed to vendors (authorized AFEs), which were not accrued and are excluded from the above table but are budgeted for and expected to be made unless circumstances change.

(d) Operating leases and commitments include office space and equipment obligations that have non-cancelable lease terms in excess of one year of

$13.5 million and future minimum payments for other operating commitments of $1.7 million.

(e) Asset retirement obligations represent the undiscounted future plugging and abandonment expenses on oil and natural gas properties and related facilities disposal at the completion of field life. Please read Note 7 of Notes to Consolidated Financial Statements included in Item 1. Financial Statements for additional information regarding our asset retirement obligations.

*Other contingencies and commitments*. In order to facilitate ongoing sales of our oil production in the CCA, we ship a portion of our production in pipelines downstream and sell to purchasers at major U.S. market hubs. From time to time, shipping delays, purchaser stipulations, or other conditions may require that we sell our oil production in periods subsequent to the period in which it is produced. In such case, the deferred sale would have an adverse effect in the period of production on reported production volumes, oil and natural gas revenues, and costs as measured on a unit-of-production basis.

The marketing of our CCA oil production is mainly dependent on transportation through the Bridger, Poplar, and Butte pipelines to markets in the Guernsey, Wyoming area. Recently, alternative transportation routes and markets have been developed by moving a portion of the crude oil production through Enbridge to the Clearbrook, Minnesota hub. In addition, new markets to the west have been identified and a portion of our crude oil is being moved that direction through the Rocky Mountain Pipeline. To a lesser extent, our production also depends on transportation through Platte Pipeline to Wood River, Illinois as well as other pipelines connected to the Guernsey, Wyoming area. While shipments on Platte Pipeline are currently oversubscribed and subject to apportionment since December 2005, we were allocated transportation effective January 1, 2007. However, further restrictions on available capacity to transport oil through any of the above mentioned pipelines, or any other pipelines, or any refinery upsets could have a material adverse effect on our production volumes and the prices we receive for our production.

We expect the differential between the NYMEX price of crude oil and the wellhead price we receive to remain approximately constant or to slightly widen in the third quarter of 2007 as compared to the second quarter of 2007. In recent years, production increases from competing Canadian and Rocky Mountain producers, in conjunction with limited refining and pipeline capacity from the Rocky Mountain area, have gradually widened this differential. We cannot accurately predict crude oil differentials. Natural gas differentials are expected to remain approximately constant or to widen slightly in the third quarter

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of 2007 as compared to the second quarter of 2007. Increases in the differential between the NYMEX price for oil and natural gas and the wellhead price we receive could have a material adverse effect on our results of operations, financial position, and cash flows.

**Liquidity**

Cash on hand, internally generated cash flows, and the borrowing capacity under our revolving credit facilities are our major sources of liquidity. We also have the ability to adjust our level of capital expenditures. We may use other sources of capital, including the issuance of additional debt or equity securities, to fund any major acquisitions we might secure in the future and to maintain our financial flexibility.

***Internally generated cash flows.*** Our internally generated cash flows, results of operations, and financing for our operations are dependent on oil and natural gas prices. Realized oil and natural gas prices for the first six months of 2007 decreased by eight percent and increased by two percent, respectively, as compared to the first six months of 2006. These prices have historically fluctuated widely in response to changing market forces. For the first six months of 2007, approximately 68 percent of our production was oil. As we previously discussed, our oil wellhead differentials during the first six months of 2007 tightened as compared to the first six months of 2006, favorably impacting the amount of oil revenues we received on our oil production. To the extent oil and natural gas prices decline or we experience significant widening of our wellhead differentials, our earnings, cash flows from operations, and availability under our revolving credit facilities may be adversely impacted. Prolonged periods of low oil and natural gas prices or sustained wider than historical wellhead differentials could cause us to not be in compliance with financial covenants under our revolving credit facilities and thereby affect our liquidity. We believe that our internally generated cash flows and unused availability under our revolving credit facilities are sufficient to fund our planned capital expenditures for the foreseeable future.

***Revolving credit facilities.*** Our principal source of short-term liquidity is our revolving credit facilities, which mature on March 7, 2012.

On March 7, 2007, we entered into the Encore Credit Agreement with a bank syndicate comprised of Bank of America, N.A. and other lenders. The Encore Credit Agreement amended and restated our Amended and Restated Credit Agreement dated as of August 19, 2004, as amended. The borrowing base is redetermined semi-annually and upon requested special redeterminations and may be increased or decreased, up to a maximum of $1.25 billion. The borrowing base on June 30, 2007 was $900 million.

Also on March 7, 2007, EEPO entered into the EEPO Credit Agreement with a bank syndicate comprised of Bank of America, N.A. and other lenders. The EEPO Credit Agreement provides for revolving credit loans to be made to EEPO from time to time and letters of credit to be issued from time to time for the account of EEPO or any of its restricted subsidiaries. The borrowing base is redetermined semi-annually and upon requested special redeterminations and may be increased or decreased, up to a maximum of $300 million. The borrowing base on June 30, 2007 was $115 million, and EEPO has the option of borrowing up to $10 million in excess of the borrowing base for a certain period of time following the closing date of the MLP.

On June 30, 2007, we had $707 million outstanding and $298 million available to borrow under our revolving credit facilities. On August 1, 2007, we had $720.5 million outstanding and $284.5 million available to borrow under our revolving credit facilities. Please read Note 8 of Notes to Consolidated Financial Statements included in Item 1. Financial Statements for additional information regarding our revolving credit facilities.

***Debt covenants.*** At June 30, 2007, EEPO was in violation of the EEPO Credit Agreement covenant that requires it to maintain a ratio of consolidated EBITDA (as defined in the EEPO Credit Agreement) to the sum of consolidated net interest expense plus letter of credit fees of not less than 2.5 to 1.0. EEPO requested and obtained a waiver from the bank syndicate for the June 30, 2007 violation. Amounts outstanding under the EEPO Credit Agreement have continued to be classified as long-term debt in the accompanying Consolidated Balance Sheet as we have the ability and intent to refinance borrowings, on a long-term basis, should any amounts become due and payable within the next twelve months under the EEPO Credit Agreement. We were in compliance with all of our other debt covenants at June 30, 2007.

***Letters of credit*.** As of June 30, 2007, we had $20 million in outstanding letters of credit all of which relate to the ExxonMobil joint development agreement. As of August 1, 2007, we had $20 million in outstanding letters of credit all of which relate to the ExxonMobil joint development agreement.

**Critical Accounting Policies and Estimates**

On January 1, 2007, we adopted the provisions of FIN 48. FIN 48 clarifies the accounting for uncertainty in income taxes recognized in a company s financial statements in accordance with SFAS 109. FIN 48 prescribes a recognition threshold and measurement attribute for the financial statement recognition and measurement of a tax position taken or expected to be taken in a tax return. See Note 9 of Notes to Consolidated Financial Statements included in Item 1. Financial Statements for more information.

Please read Management s Discussion and Analysis of Financial Condition and Results of Operations Critical Accounting Policies and Estimates in our 2006 Annual Report on Form 10-K for more information.

**New Accounting Pronouncements**

The effects of new accounting pronouncements are discussed in Note 2 of Notes to Consolidated Financial Statements included in Item 1. Financial Statements.

## Item 3. Quantitative and Qualitative Disclosures About Market Risk

The information included in Quantitative and Qualitative Disclosures about Market Risk in our 2006 Annual Report on Form 10-K is incorporated herein by reference. Such information includes a description of our potential exposure to market risks, including commodity price risk and interest rate risk.

***Commodity Price Sensitivity***

Our outstanding derivative contracts as of June 30, 2007 are discussed in Note 6 of Notes to Consolidated Financial Statements included in Item 1. Financial Statements. As of June 30, 2007, the fair market value of our oil derivative contracts was a net $10.3 million asset and the fair market value of our natural gas derivative contracts was a net $6.8 million asset. Based on our open commodity derivative positions at June 30, 2007, a $1.00 per Bbl and $1.00 per Mcf increase in the NYMEX prices for oil and natural gas would result in a decrease to our net derivative fair value asset of approximately $10.2 million, while a $1.00 decrease in the respective NYMEX prices for oil and natural gas would result in an increase to our net derivative fair value asset of approximately $18.3 million.

***Interest Rate Sensitivity***

At June 30, 2007, we had total long-term debt of $1.3 billion, which is recorded net of discount of $6.0 million. Of this amount, $150 million bears interest at a fixed rate of 6 1/4 percent, $300 million bears interest at a fixed rate of 6 percent, and $150 million bears interest at a fixed rate of 7 1/4 percent. The remaining outstanding long-term debt balance of $707 million is under our revolving credit facilities and is subject to floating market rates of interest that are linked to LIBOR.

At this level of floating rate debt, if LIBOR increased one percent, we would incur an additional $7.1 million of interest expense per year, and if the rate decreased one percent, we would incur $7.1 million less. Additionally, if LIBOR increased one percent, we estimate the fair value of our fixed rate debt at June 30, 2007 would decrease from $543.6 million to $509.4 million, and if the rate decreased one percent, we estimate the fair value would increase to $580.8 million.

## Item 4. Controls and Procedures

In accordance with the Securities Exchange Act of 1934 (the Exchange Act ) Rules 13a-15 and 15d-15, we carried out an evaluation, under the supervision and with the participation of management, including our Chief Executive Officer and Chief Financial Officer, of the effectiveness of our disclosure controls and procedures as of June 30, 2007. Based on that evaluation, our Chief Executive Officer and Chief Financial Officer concluded that our disclosure controls and procedures were effective as of June 30, 2007 to provide reasonable assurance that information required to be disclosed in our reports filed or submitted under the Exchange Act is recorded, processed, summarized, and reported within the time periods specified in the SEC s rules and forms.

There were no changes in our internal control over financial reporting that occurred during the three months ended June 30, 2007 that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

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## PART II. OTHER INFORMATION

### Item 1. Legal Proceedings

We are a party to ongoing legal proceedings in the ordinary course of business. Management does not believe the result of these legal proceedings will have a material adverse effect on us.

### Item 1A. Risk Factors

In addition to the other information set forth in this report, you should carefully consider the factors discussed in Part I, Item 1A. Risk Factors in our Annual Report on Form 10-K for the year ended December 31, 2006, which could materially affect our business, financial condition, and/or future results. The risks described in our Annual Report on Form 10-K are not the only risks we face. Additional risks and uncertainties not currently known to us or that we currently deem to be immaterial also may materially adversely affect our business, financial condition, or results of operations.

### Item 2. Unregistered Sales of Equity Securities and Use of Proceeds

**Issuer Purchases of Equity Securities**

The following table summarizes purchases of our common stock during the second quarter of 2007:

| Month | Total Number of Shares Purchased | Average Price Paid per Share | Total Number of Shares Purchased as Part of Publicly Announced Plans or Programs | Maximum Number of Shares That May Yet Be Purchased Under the Plans or Programs |
|---|---|---|---|---|
| April | | $ | | NA |
| May | | | | NA |
| June (a) | 5,545 | 27.80 | | NA |
| Total | 5,545 | 27.80 | | NA |

(a) We do not have a formal common stock repurchase program. During the second quarter of 2007, certain employees surrendered shares of common stock to pay income tax withholding obligations in conjunction with vesting of restricted shares.

**Item 4. Submission of Matters to a Vote of Security Holders**

Our annual meeting of stockholders was held Thursday, May 3, 2007. The items submitted to stockholders for vote were the election of eight nominees to serve on the Board during 2007 and until our next annual meeting and to ratify the appointment of the independent registered public accounting firm for 2007. Notice of the meeting and proxy information was distributed to stockholders prior to the meeting in accordance with law. There were no solicitations in opposition to the nominees. Out of a total of 54,179,572 shares of our common stock outstanding and entitled to vote, 50,959,314 shares (94.1 percent) were present at the meeting in person or by proxy.

*Election of Directors*

There were eight nominees for election to serve as our directors. The vote tabulation with respect to each nominee to the Board was as follows:

| NOMINEE | FOR | WITHHELD |
|---|---|---|
| I. Jon Brumley | 50,250,218 | 709,096 |
| Jon S. Brumley | 50,645,855 | 313,459 |
| John A. Bailey | 50,831,128 | 128,186 |
| Martin C. Bowen | 50,796,878 | 162,436 |
| Ted Collins, Jr. | 45,363,918 | 5,595,396 |
| Ted A. Gardner | 50,831,128 | 128,186 |
| John V. Genova | 50,831,168 | 128,146 |
| James A. Winne III | 50,747,610 | 211,704 |

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*Appointment of Independent Registered Public Accounting Firm*

The Board recommended that our stockholders ratify the appointment of Ernst & Young LLP as our independent registered public accounting firm. The vote tabulation with respect to the ratification of the appointment of the independent registered public accounting firm was as follows:

| FOR | AGAINST | ABSTAIN |
|---|---|---|
| 50,856,253 | 58,016 | 45,045 |

**Item 6. Exhibits**

Exhibits

2.1 Purchase and Sale Agreement dated May 16, 2007 between Crow Creek and Encore Operating, L.P. (incorporated by reference from the Company s Current Report on Form 8-K, filed with the SEC on July 6, 2007).

3.1 Second Amended and Restated Certificate of Incorporation of the Company (incorporated by reference from the Company s Quarterly Report on Form 10-Q for the fiscal quarter ended September 30, 2001, filed with the SEC on November 7, 2001).

3.1.2 Certificate of Amendment to Second Amended and Restated Certificate of Incorporation of the Company (incorporated by reference from the Company s Quarterly Report on Form 10-Q for the fiscal quarter ended March 31, 2005, filed with the SEC on May 5, 2005).

3.2 Second Amended and Restated Bylaws of the Company (incorporated by reference from the Company s Quarterly Report on Form 10-Q for the fiscal quarter ended September 30, 2001, filed with the SEC on November 7, 2001).

10.1* First Amended and Restated Agreement of Limited Partnership of Encore Energy Partners LP, dated as of May 10, 2007.

10.2* Amendment No. 1 to the First Amended and Restated Agreement of Limited Partnership of Encore Energy Partners LP, dated as of July 3, 2007.

31.1* Rule 13a-14(a)/15d-14(a) Certification (Principal Executive Officer).

31.2* Rule 13a-14(a)/15d-14(a) Certification (Principal Financial Officer).

32.1* Section 1350 Certification (Principal Executive Officer).

32.2* Section 1350 Certification (Principal Financial Officer).

99.1* Statement showing computation of ratios of earnings to fixed charges.

* Filed herewith.

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## ENCORE ACQUISITION COMPANY
## SIGNATURE

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

ENCORE ACQUISITION COMPANY

Date: August 9, 2007

/s/ Robert C. Reeves
Robert C. Reeves
Senior Vice President, Chief Financial Officer, and Treasurer

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