ENCORE ACQUISITION CO
Form 10-Q
October 31, 2008

Table of Contents

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 September 30, 2008

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, a non-accelerated filer, or a smaller reporting company. See the definitions of large accelerated filer, accelerated filer and smaller reporting company in Rule 12b-2 of the Exchange Act. (Check one):

Large accelerated filer þ	Accelerated filer o	Non-accelerated filer o (Do not check if a smaller reporting company)	Smaller reporting company 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 October 28, 2008	52,764,231

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 United States Securities and Exchange Commission (the 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. Forward-looking statements can be identified by the fact that they do not relate strictly to historical or current facts. These statements may include words such as may, will, could, anticipate, estimate, expect, project, intend, plan, believe, should, predict, potential, pursue, target, cont terms of similar meaning. Readers are cautioned not to place undue reliance on such forward-looking statements, which speak only as of the date of this Report. 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 2007 Annual Report on Form 10-K and in our other filings with the SEC. If one or more of these risks or uncertainties materialize (or the consequences of such a development changes), or should underlying assumptions prove incorrect, actual outcomes may vary materially from those forecasted or expected. 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.

Table of Contents

ENCORE ACQUISITION COMPANY
GLOSSARY

The following are abbreviations and definitions of certain terms used in this Report. The definitions of proved developed reserves, proved reserves, and proved undeveloped reserves have been abbreviated from the applicable definitions contained in Rule 4-10(a)(2-4) of Regulation S-X.

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.

Completion. The installation of permanent equipment for the production of oil or natural gas.

Council of Petroleum Accountants Societies (COPAS). A professional organization of oil and gas accountants that maintains consistency in accounting procedures and interpretations, including the procedures that are part of most joint operating agreements. These procedures establish a drilling rate and an overhead rate to reimburse the operator of a well for overhead costs, such as accounting and engineering.

Delay Rentals. Fees paid to the lessor of an oil and natural gas lease during the primary term of the lease prior to the commencement of production from a well.

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

Dry Hole. A well found to be incapable of producing hydrocarbons in sufficient quantities such that proceeds from the sale of such production would exceed production costs.

Dry Gas. Natural gas comprised of over 90 percent methane and suitable for use by customers of local gas distribution companies.

EAC. Encore Acquisition Company, a Delaware corporation, together with its subsidiaries.

ENP. Encore Energy Partners LP, a publicly traded Delaware limited partnership, together with its subsidiaries.

Exploratory Well. A well drilled to find and produce oil or natural gas in an unproved area, to find a new reservoir in a field previously producing oil or natural gas in another reservoir, or to extend a known reservoir.

Field. An area consisting of a single reservoir or multiple reservoirs, all grouped on or related to the same individual geological structural feature and/or stratigraphic condition.

Gross Acres or Gross Wells. The total acres or wells, as the case may be, in which an entity owns a working interest.

Lease Operations Expense (LOE). All direct and allocated indirect costs of producing oil and natural gas after completion of drilling. Such costs include labor, superintendence, supplies, repairs, maintenance, and direct overhead charges.

LIBOR. London Interbank Offered Rate.

MBbl. One thousand Bbls.

MBOE. One thousand BOE.

Mcf. One thousand cubic feet, used in reference to natural gas.

Mcf/D. One Mcf per day.

MMcf. One million cubic feet, used in reference to natural gas.

Natural Gas Liquids (NGLs). The combination of ethane, propane, butane, and natural gasolines that when removed from natural gas become liquid under various levels of higher pressure and lower temperature.

Net Acres or Net Wells. Gross acres or wells, as the case may be, multiplied by the working interest percentage owned by an entity.

Net Profits Interest (NPI). An interest that entitles the owner to a specified share of net profits from production of hydrocarbons.

NYMEX. New York Mercantile Exchange.

Oil. Crude oil, condensate, and NGLs.

Operator. The entity responsible for the exploration, development, and production of an oil or natural gas well or lease.

Production Margin. Oil and natural gas revenues less LOE and production, ad valorem, and severance taxes.

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

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

Table of Contents

ENCORE ACQUISITION COMPANY

Proved Undeveloped Reserves. Proved reserves that are expected to be recovered from new wells on undrilled acreage for which the existence and recoverability of such reserves can be estimated with reasonable certainty, or from existing wells where a relatively major expenditure is required for recompletion. Proved undeveloped reserves included unrealized production response from enhanced recovery techniques that have been proved effective by actual tests in the area and in the same reservoir.

Recompletion. The completion for production of an existing well bore in another formation from that in which the well has been previously completed.

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

Secondary Recovery. Enhanced recovery of oil or natural gas from a reservoir beyond the oil or natural gas that can be recovered by normal flowing and pumping operations. Secondary recovery techniques involve maintaining or enhancing reservoir pressure by injecting water, gas, or other substances into the formation. The purpose of secondary recovery is to maintain reservoir pressure and to displace hydrocarbons toward the wellbore. The most common secondary recovery techniques are gas injection and waterflooding.

Successful Well. A well capable of producing oil and/or natural gas in commercial quantities.

Tertiary Recovery. An enhanced recovery operation that normally occurs after waterflooding in which chemicals or natural gases are used as the injectant.

Waterflood. A secondary recovery operation in which water is injected into the producing formation in order to maintain reservoir pressure and force oil toward and into the producing wells.

Working Interest. An interest in an oil or natural gas lease that gives the owner the right to drill for and produce oil and natural gas on the leased acreage and requires the owner to pay a share of the production and development costs.

Workover. Operations on a producing well to restore or increase production.

Table of Contents

PART I. FINANCIAL INFORMATION

Item 1. Financial Statements

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

	September 30, 2008 (unaudited)	December 31, 2007
ASSETS		
Current assets:		
Cash and cash equivalents	$ 3,827	$ 1,704
Accounts receivable, net of allowance for doubtful accounts of $6,045	163,970	134,880
Inventory	19,550	16,257
Derivatives	76,143	9,722
Deferred taxes	14,204	20,420
Income taxes receivable	29,442	2,661
Other	3,537	2,866
Total current assets	310,673	188,510
Properties and equipment, at cost successful efforts method:		
Proved properties, including wells and related equipment	3,305,270	2,845,776
Unproved properties	129,515	63,352
Accumulated depletion, depreciation, and amortization	(670,086)	(489,004)
	2,764,699	2,420,124
Other property and equipment	22,187	21,750
Accumulated depreciation	(11,443)	(10,733)
	10,744	11,017
Goodwill	60,606	60,606
Derivatives	34,971	34,579
Long-term receivables	75,144	40,945
Other	29,304	28,780
Total assets	$ 3,286,141	$ 2,784,561
LIABILITIES AND STOCKHOLDERS EQUITY		
Current liabilities:		
Accounts payable	$ 32,112	$ 21,548
Accrued liabilities:		
Lease operations expense	19,988	15,057

Development capital	85,412	48,359
Interest	12,657	12,795
Production, ad valorem, and severance taxes	44,649	24,694
Marketing	2,889	8,721
Derivatives	87,989	39,337
Oil and natural gas revenues payable	16,731	13,076
Other	23,390	21,143
Total current liabilities	325,817	204,730
Derivatives	51,924	47,091
Future abandonment cost, net of current portion	32,478	27,371
Deferred taxes	416,528	312,914
Long-term debt	1,217,604	1,120,236
Other	2,398	1,530
Total liabilities	2,046,749	1,713,872
Commitments and contingencies (see Note 16)		
Minority interest in consolidated partnership	125,181	122,534
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, 52,155,256 and 53,303,464 issued and outstanding, respectively	523	534
Additional paid-in capital	540,140	538,620
Treasury stock, at cost, none and 17,690 shares, respectively		(590)
Retained earnings	573,395	411,377
Accumulated other comprehensive income (loss)	153	(1,786)
Total stockholders equity	1,114,211	948,155
Total liabilities and stockholders equity	$ 3,286,141	$ 2,784,561

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

1

Table of Contents

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

	Three months ended September 30,		Nine months ended September 30,	
	2008	**2007**	**2008**	**2007**
Revenues:				
Oil	$ 268,543	$ 159,295	$ 776,001	$ 377,514
Natural gas	66,772	32,439	182,973	110,548
Marketing	2,163	3,282	8,740	27,139
Total revenues	337,478	195,016	967,714	515,201
Expenses:				
Production:				
Lease operations	48,966	37,114	130,013	105,186
Production, ad valorem, and severance taxes	33,350	20,003	95,845	51,750
Depletion, depreciation, and amortization	58,545	49,026	159,114	136,372
Impairment of long-lived assets	26,292		26,292	
Exploration	13,381	8,920	30,462	23,856
General and administrative	15,303	12,668	36,549	26,216
Marketing	1,855	4,089	9,362	27,607
Derivative fair value loss (gain)	(239,435)	15,786	82,093	68,166
Other operating	4,073	6,351	9,805	13,667
Total expenses	(37,670)	153,957	579,535	452,820
Operating income	375,148	41,059	388,179	62,381
Other income (expenses):				
Interest	(18,124)	(23,933)	(54,669)	(68,040)
Other	1,553	857	3,090	1,889
Total other expenses	(16,571)	(23,076)	(51,579)	(66,151)
Income (loss) before income taxes and minority interest	358,577	17,983	336,600	(3,770)
Income tax provision	(121,184)	(8,986)	(118,595)	(1,490)
Minority interest in loss (income) of consolidated partnership	(31,086)	2,988	(16,198)	2,988
Net income (loss)	$ 206,307	$ 11,985	$ 201,807	$ (2,272)

Net income (loss) per common share:				
Basic	$ 3.95	$ 0.23	$ 3.85	$ (0.04)
Diluted	$ 3.80	$ 0.22	$ 3.70	$ (0.04)
Weighted average common shares outstanding:				
Basic	52,258	53,198	52,466	53,140
Diluted	53,521	54,179	53,670	53,140

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

Table of Contents

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 Income (Loss)	Total Stockholders Equity
Balance at December 31, 2007	53,321	$ 534	$ 538,620	(18)	$ (590)	$ 411,377	$ (1,786)	$ 948,155
Exercise of stock options and vesting of restricted stock	278	3	1,750					1,753
Repurchase and retirement of common stock	(1,398)	(14)	(13,687)			(36,299)		(50,000)
Purchase of treasury stock				(28)	(954)			(954)
Cancellation of treasury stock	(46)		(465)	46	1,544	(1,079)		
Non-cash equity-based compensation			10,320					10,320
ENP distributions to holders of management incentive units						(2,411)		(2,411)
Adjustment to reflect gain on issuance of ENP common units			3,458					3,458
Other			144					144
Components of comprehensive income:								
Net income						201,807		201,807
Change in deferred hedge gain on interest rate swaps, net of tax of $103 and net of minority interest of $132							153	153
							1,786	1,786

Amortization of deferred loss on commodity derivative contracts, net of tax of $1,071							
Total comprehensive income							203,746
Balance at September 30, 2008	52,155	$ 523	$ 540,140	$	$ 573,395	$ 153	$ 1,114,211

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

3

Table of Contents

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

	Nine months ended September 30, 2008	Nine months ended September 30, 2007
Cash flows from operating activities:		
Net income (loss)	$ 201,807	$ (2,272)
Adjustments to reconcile net income (loss) to net cash provided by operating activities:		
Depletion, depreciation, and amortization	159,114	136,372
Impairment of long-lived assets	26,292	
Non-cash exploration expense	27,699	22,511
Deferred taxes	109,653	1,374
Non-cash equity-based compensation expense	9,963	12,790
Non-cash derivative loss	38,203	87,108
Loss (gain) on disposition of assets	(691)	5,918
Minority interest in income (loss) of consolidated partnership	16,198	(2,988)
Other	7,349	6,055
Changes in operating assets and liabilities, net of effects from acquisitions:		
Accounts receivable	(31,135)	(31,064)
Current derivatives	(12,196)	(15,303)
Other current assets	(30,745)	(1,858)
Long-term derivatives	(7,028)	(22,301)
Other assets	(2,094)	(4,428)
Accounts payable	(2,476)	4,416
Other current liabilities	20,581	17,810
Other noncurrent liabilities	(1,507)	(496)
Net cash provided by operating activities	528,987	213,644
Cash flows from investing activities:		
Proceeds from disposition of assets	1,230	291,339
Purchases of other property and equipment	(2,416)	(2,443)
Acquisition of oil and natural gas properties	(116,767)	(839,945)
Development of oil and natural gas properties	(384,864)	(259,457)
Net advances to working interest partners	(33,277)	(22,644)
Net cash used in investing activities	(536,094)	(833,150)
Cash flows from financing activities:		
Proceeds from issuance of ENP common units, net of issuance costs		171,220
Repurchase of common stock	(50,000)	

Exercise of stock options and vesting of restricted stock, net of treasury stock purchases	799	1,053
Proceeds from long-term debt, net of issuance costs	1,070,238	1,269,291
Payments on long-term debt	(974,500)	(805,428)
ENP distributions	(19,525)	
Payment of commodity derivative contract premiums	(30,822)	(19,219)
Change in cash overdrafts	13,040	10,293
Net cash provided by financing activities	9,230	627,210
Increase in cash and cash equivalents	2,123	7,704
Cash and cash equivalents, beginning of period	1,704	763
Cash and cash equivalents, end of period	$ 3,827	$ 8,467

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

Table of Contents

ENCORE ACQUISITION COMPANY
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS
(unaudited)

Note 1. About EAC

EAC is engaged in the acquisition and development of oil and natural gas reserves from onshore fields in the United States. Since 1998, EAC 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. EAC 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, and the East Texas Basin.

Note 2. Basis of Presentation

EAC s consolidated financial statements include the accounts of wholly owned and majority-owned subsidiaries. All material intercompany balances and transactions have been eliminated in consolidation.

In the opinion of management, the accompanying unaudited consolidated financial statements include all adjustments necessary to present fairly, in all material respects, EAC s financial position as of September 30, 2008, results of operations for the three and nine months ended September 30, 2008 and 2007, and cash flows for the nine months ended September 30, 2008 and 2007. 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 EAC s 2007 Annual Report on Form 10-K.

Minority Interest

In February 2007, EAC formed ENP to acquire, exploit, and develop oil and natural gas properties and to acquire, own, and operate related assets. In September 2007, ENP completed its initial public offering (IPO). As of September 30, 2008 and December 31, 2007, EAC owned approximately 66.7 percent and 58.0 percent, respectively, of ENP s common units, as well as all of the interests of Encore Energy Partners GP LLC (GP LLC), a Delaware limited liability company and ENP s general partner, which is an indirect wholly owned non-guarantor subsidiary of EAC. Considering the presumption of control of GP LLC in accordance with Emerging Issues Task Force Issue No. 04-5, *Determining Whether a General Partner, or the General Partners as a Group, Controls a Limited Partnership or Similar Entity When the Limited Partners Have Certain Rights* , the financial position, results of operations, and cash flows of ENP are consolidated with those of EAC. EAC elected to account for gains on ENP s issuance of common units as capital transactions as permitted by Staff Accounting Bulletin (SAB) Topic 5H, *Accounting for Sales of Stock by a Subsidiary* . See Note 18. ENP for additional discussion.

As presented in the accompanying Consolidated Balance Sheets, Minority interest in consolidated partnership as of September 30, 2008 and December 31, 2007 of $125.2 million and $122.5 million, respectively, represents third-party ownership interests in ENP. As presented in the accompanying Consolidated Statements of Operations, Minority interest in income of consolidated partnership for the three and nine months ended September 30, 2008 of $31.1 million and $16.2 million, respectively, and Minority interest in loss of consolidated partnership for each of the three and nine months ended September 30, 2007 of $3.0 million represents the net income or loss of ENP attributable to third-party owners.

5

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

Reclassifications

Certain amounts in prior periods have been reclassified to conform to the current period presentation. In particular, income taxes receivable on the accompanying Consolidated Balance Sheets have been disaggregated from other current assets.

New Accounting Pronouncements

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

In September 2006, the Financial Accounting Standards Board (FASB) issued SFAS 157, which: (1) standardizes the definition of fair value; (2) establishes a framework for measuring fair value in generally accepted accounting principles (GAAP); and (3) 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 require any new fair value measurements. SFAS 157 was prospectively effective for financial assets and liabilities for financial statements issued for fiscal years beginning after November 15, 2007, and interim periods within those fiscal years. In February 2008, the FASB issued FASB Staff Position (FSP) No. FAS 157-2, *Effective Date of FASB Statement No. 157* (FSP FAS 157-2), which delayed the effective date of SFAS 157 for one year for nonfinancial assets and liabilities, except those that are recognized or disclosed at fair value in the financial statements on a recurring basis (at least annually). EAC elected a partial deferral of SFAS 157 for all instruments within the scope of FSP FAS 157-2, including but not limited to, its asset retirement obligations and indefinite lived assets. EAC will continue to evaluate the impact of SFAS 157 on these instruments during the deferral period. The adoption of SFAS 157 on January 1, 2008, as it relates to financial assets and liabilities, did not have a material impact on EAC s results of operations or financial condition. See Note 7. Fair Value Measurements for additional discussion.

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, which permits entities to measure many financial instruments and certain other assets and liabilities at fair value on an instrument-by-instrument basis. SFAS 159 also allows entities an irrevocable option to measure eligible items at fair value at specified election dates, with resulting changes in fair value reported in earnings. SFAS 159 was effective for fiscal years beginning after November 15, 2007. EAC did not elect the fair value option for eligible instruments and therefore, the adoption of SFAS 159 on January 1, 2008 did not have an impact on EAC s results of operations or financial condition. EAC will assess the impact of electing the fair value option for any eligible instruments acquired in the future. Electing the fair value option for such instruments could have a material impact on EAC s future results of operations or financial condition.

FSP Interpretation 39-1, Amendment of FASB Interpretation No. 39 (FSP FIN 39-1)

In April 2007, the FASB issued FSP FIN 39-1, which amends FASB Interpretation (FIN) No. 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 was effective for fiscal years beginning after November 15, 2007. The adoption of FSP FIN 39-1 on January 1, 2008 did not have an impact on EAC s results of operations or financial condition.

SFAS No. 141 (revised 2007), Business Combinations (SFAS 141R)

In December 2007, the FASB issued SFAS 141R, which replaces SFAS No. 141, *Business Combinations*". SFAS 141R establishes principles and requirements for the reporting entity in a business combination, including: (1) recognition and measurement in the financial statements of the identifiable assets acquired, the liabilities assumed, and any noncontrolling interest in the acquiree; (2) recognition and measurement of goodwill acquired in the business combination or a gain from a bargain purchase; and (3) determination of the information to be disclosed to enable financial statement users to evaluate the nature and financial effects of the business combination. SFAS 141R is prospectively effective for business combinations consummated in fiscal years beginning on or after December 15, 2008 with early application prohibited. EAC is evaluating the impact SFAS 141R will have on its results of operations and financial condition and the reporting of future acquisitions in the

6

Table of Contents

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

consolidated financial statements.

SFAS No. 160, Noncontrolling Interests in Consolidated Financial Statements an amendment to ARB No. 51 (SFAS 160)

In December 2007, the FASB issued SFAS 160, which amends Accounting Research Bulletin No. 51, "*Consolidated Financial Statements* to establish accounting and reporting standards for the noncontrolling interest in a subsidiary and for the deconsolidation of a subsidiary. SFAS 160 is effective for fiscal years beginning on or after December 15, 2008. SFAS 160 clarifies that a noncontrolling interest in a subsidiary, which is sometimes referred to as minority interest, is an ownership interest in the consolidated entity that should be reported as a component of equity in the consolidated financial statements. Among other requirements, SFAS 160 requires consolidated net income to be reported at amounts that include the amounts attributable to both the parent and the noncontrolling interest and the disclosure of consolidated net income attributable to the parent and to the noncontrolling interest on the face of the consolidated statement of operations. EAC is evaluating the impact SFAS 160 will have on its results of operations or financial condition.

SFAS No. 161, Disclosures about Derivative Instruments and Hedging Activities an amendment of FASB Statement No. 133 (SFAS 161)

In March 2008, the FASB issued SFAS 161, which amends SFAS No. 133, *Accounting for Derivative Instruments and Hedging Activities* (SFAS 133). SFAS 161 requires enhanced disclosures about: (1) how and why an entity uses derivative instruments; (2) how derivative instruments and related hedged items are accounted for under SFAS 133 and its related interpretations; and (3) how derivative instruments and related hedged items affect an entity s financial position, financial performance, and cash flows. SFAS 161 is effective for fiscal years beginning on or after November 15, 2008, with early application encouraged. The adoption of SFAS 161 will require additional disclosures regarding EAC s derivative instruments; however, it will not impact EAC s results of operations or financial condition.

SFAS No. 162, The Hierarchy of Generally Accepted Accounting Principles (SFAS 162)

In May 2008, the FASB issued SFAS 162, which identifies the sources of accounting principles and the framework for selecting the principles to be used in the preparation of financial statements of nongovernmental entities that are presented in conformity with GAAP. SFAS 162 is effective 60 days following the SEC s approval of the Public Company Accounting Oversight Board amendments to AU Section 411, *The Meaning of Present Fairly in Conformity With Generally Accepted Accounting Principles* . The adoption of SFAS 162 will not impact EAC s results of operations or financial condition.

FSP No. EITF 03-6-1, Determining Whether Instruments Granted in Share-Based Payment Transactions Are Participating Securities (FSP EITF 03-6-1)

In June 2008, the FASB issued FSP EITF 03-6-1, which addresses whether instruments granted in equity-based payment transactions are participating securities prior to vesting and, therefore, need to be included in the earnings allocation for computing basic earnings per share (EPS) under the two-class method described by SFAS No. 128, *Earnings per Share* . FSP EITF 03-6-1 is retrospectively effective for financial statements issued for fiscal years beginning after December 15, 2008, and interim periods within those years, with early application prohibited. EAC is evaluating the impact the adoption of FSP EITF 03-6-1 will have on its EPS calculations.

Note 3. Acquisitions and Dispositions

Acquisitions

In January 2007, EAC entered into a purchase and sale agreement with certain subsidiaries of Anadarko Petroleum Corporation (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 in April 2007. The Williston Basin acquisition was treated as a reverse like-kind exchange under Section 1031 of the Internal Revenue Code of 1986, as amended, (the Code) and I.R.S. Revenue Procedure 2000-37 with the Mid-Continent disposition discussed below. The total purchase price for the Williston Basin assets was approximately $392.1 million, including transaction costs of approximately $1.3 million.

Also in January 2007, EAC 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

Table of Contents

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

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. Prior to closing, EAC assigned the rights and duties under the purchase and sale agreement relating to the Elk Basin assets to Encore Energy Partners Operating LLC (OLLC), a Delaware limited liability company and wholly owned subsidiary of ENP, and the rights and duties under the purchase and sale agreement relating to the Gooseberry assets to Encore Operating, L.P. (Encore Operating), a Texas limited partnership and indirect wholly owned guarantor subsidiary of EAC. The closing of the Big Horn Basin acquisition occurred in March 2007. The total purchase price for the Big Horn Basin assets was approximately $393.6 million, including transaction costs of approximately $1.3 million.

EAC financed the acquisitions of the Gooseberry assets and Williston Basin assets through borrowings under its revolving credit facility. ENP financed the acquisition of the Elk Basin assets through a $93.7 million contribution from EAC, $120 million of borrowings under a subordinated credit agreement with EAP Operating, LLC, a Delaware limited liability company and direct wholly owned guarantor subsidiary of EAC, and borrowings under OLLC s revolving credit facility.

Dispositions

In June 2007, EAC completed the sale of certain oil and natural gas properties in the Mid-Continent area, and in July 2007, additional Mid-Continent properties that were subject to preferential rights were sold. EAC received total net proceeds of approximately $294.8 million, after deducting transaction costs of approximately $3.6 million, and recorded a loss on sale of approximately $7.4 million. The disposed properties included certain properties in the Anadarko and Arkoma Basins of Oklahoma. EAC retained material oil and natural gas interests in other properties in these basins and remains active in those areas. Proceeds from the Mid-Continent asset disposition were used to reduce outstanding borrowings under EAC s revolving credit facility.

Pro Formas

The following pro forma condensed financial data was derived from the historical financial statements of EAC and from the accounting records of Anadarko to give effect to the Big Horn Basin and Williston Basin asset acquisitions and the Mid-Continent asset disposition as if they had each occurred on January 1, 2007. The pro forma 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 Basin and Williston Basin asset acquisitions and the Mid-Continent asset disposition taken place on January 1, 2007 and is not intended to be a projection of future results.

	Three months ended	Nine months ended
	September 30, 2007	
	(in thousands, except per share amounts)	
Pro forma total revenues	$ 182,120	$ 509,886
Pro forma net income (loss)	$ 11,242	$ (6,683)
Pro forma net income (loss) per common share:		
Basic	$ 0.21	$ (0.13)
Diluted	$ 0.21	$ (0.13)

8

Table of Contents

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

Note 4. Inventory

Inventory is composed 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. Inventory consisted of the following as of the dates indicated:

	September 30, 2008	December 31, 2007
	(in thousands)	
Materials and supplies	$ 14,034	$ 11,567
Oil in pipelines	5,516	4,690
Total inventory	$ 19,550	$ 16,257

Note 5. Proved Properties

Amounts shown in the accompanying Consolidated Balance Sheets as Proved properties, including wells and related equipment consisted of the following as of the dates indicated:

	September 30, 2008	December 31, 2007
	(in thousands)	
Proved leasehold costs	$ 1,391,032	$ 1,346,516
Wells and related equipment Completed	1,748,063	1,408,512
Wells and related equipment In process	166,175	90,748
Total proved properties	$ 3,305,270	$ 2,845,776

Note 6. Derivative Financial Instruments

As of September 30, 2008, EAC had $76.3 million of deferred premiums payable of which $21.3 million was long-term and included in Derivatives in the non-current liabilities section of the accompanying Consolidated Balance Sheet and $55.0 million was current and included 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 October 2008 to January 2010. EAC recorded these premiums at their net present value at the time the contracts were entered into and accretes that value up to the eventual settlement price by recording interest expense each period. During the nine months ended September 30, 2008, EAC entered into deferred premium contracts valued at $53.4 million, which are non-cash financing activities.

Commodity Derivative Contracts Mark-to-Market Accounting

From time to time, EAC sells floors with a strike price below the strike price of the purchased floors in order to partially finance the premiums paid on the purchased floors. 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. As with EAC s other commodity derivative contracts, these are marked-to-market each quarter through Derivative fair value loss (gain) in the accompanying Consolidated Statements of Operations. In the following tables, the purchased floor component of these floor spreads are shown net and included with EAC s other floor contracts.

9

Table of Contents

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

The following tables summarize EAC s open commodity derivative contracts as of September 30, 2008:

Oil Derivative Contracts

Period	Average Daily Floor Volume (Bbls)	Weighted Average Floor Price (per Bbl)	Average Daily Short Floor Volume (Bbls)	Weighted Average Short Floor Price (per Bbl)	Average Daily Cap Volume (Bbls)	Weighted Average Cap Price (per Bbl)	Average Daily Swap Volume (Bbls)	Weighted Average Swap Price (per Bbl)	Asset (Liability) Fair Market Value (in thousands)
Oct. Dec. 2008									$ (4,737)
	14,880	$ 83.36		$	2,440	$ 101.99	5,000	$ 91.56	
	6,000	71.67			2,000	96.65			
	5,500	62.27							
	3,000	56.67	(4,000)	50.00					
2009 (a)									56,118
	11,630	110.00			440	97.75	2,000	90.46	
	8,000	80.00	(5,000)	50.00			3,000	89.22	
							1,000	68.70	
2010									(8,226)
	880	80.00			440	93.80			
	2,000	75.00			1,000	77.23			
2011									(4,731)
	1,880	80.00			1,440	95.41			
	1,000	70.00							
									$ 38,424

(a) In addition, ENP has a floor contract for 1,000 Bbls/D at $63.00 per Bbl and a short floor contract for 1,000 Bbls/D at $65.00 per Bbl.

Natural Gas Derivative Contracts

Period	Average Daily Floor Volume	Weighted Average Floor Price	Average Daily Short Floor Volume	Weighted Average Short Floor Price	Average Daily Cap Volume	Weighted Average Cap Price	Average Daily Swap Volume	Weighted Average Swap Price	Asset Fair Market Value

	(Mcf)	(per Mcf)	(Mcf)	(per Mcf)	(Mcf)	(per Mcf)	(Mcf)	(per Mcf)	(in thousands)
Oct. Dec. 2008									$ 4,986
	6,300	$8.18		$	6,300	$9.52	5,000	$8.14	
	11,300	7.38			7,500	8.35	5,000	7.47	
	20,000	6.35							
2009									1,969
	3,800	8.20			3,800	9.83			
	3,800	7.20							
2010									1,303
	3,800	8.20			3,800	9.58			
	3,800	7.20							
									$ 8,258

Interest Rate Swaps

In the first quarter of 2008, ENP entered into interest rate swaps whereby it swapped $100 million of floating rate debt on OLLC s revolving credit facility to a weighted average fixed rate of 3.06 percent and an expected margin of 1.25 percent. These interest rate swaps were designated as cash flow hedges. The following table summarizes ENP s open interest rate swaps as of September 30, 2008:

Term	**Notional Amount** (in thousands)	**Fixed Rate**	**Floating Rate**
October 2008-January 2011	$50,000	3.1610%	1-month LIBOR
October 2008-January 2011	25,000	2.9650%	1-month LIBOR
October 2008-January 2011	25,000	2.9613%	1-month LIBOR

10

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

As of September 30, 2008, the fair market value of ENP s interest rate swaps was a net asset of $0.8 million. During the three and nine months ended September 30, 2008, settlements of interest rate swaps increased EAC s consolidated interest expense by approximately $0.1 million and $0.2 million, respectively.

Current Period Impact

As a result of commodity derivative contracts that were previously designated as hedges, EAC recognized a pre-tax reduction in oil and natural gas revenues of $13.4 million during the three months ended September 30, 2007 and $2.9 million and $40.2 million during the nine months ended September 30, 2008 and 2007, respectively. EAC also recognized derivative fair value gains and losses related to: (1) changes in the market value of derivative contracts; (2) settlements on commodity derivative contracts; and (3) premium amortization. The following table summarizes the components of derivative fair value gains and losses for the periods indicated:

	Three months ended September 30,		Nine months ended September 30,	
	2008	**2007**	**2008**	**2007**
	(in thousands)			
Mark-to-market loss (gain) on derivative contracts	$ (276,938)	$ (3,007)	$ (12,233)	$ 17,547
Premium amortization	14,773	11,681	47,579	29,370
Settlements on commodity derivative contracts	22,730	7,112	46,747	21,249
Total derivative fair value loss (gain)	$ (239,435)	$ 15,786	$ 82,093	$ 68,166

Accumulated Other Comprehensive Income (AOCI)

At September 30, 2008, AOCI consisted entirely of deferred gains, net of tax, on ENP s interest rate swaps that are designated as hedges of $0.2 million. At December 31, 2007, AOCI consisted entirely of deferred losses, net of tax, on commodity derivative contracts that were previously designated as hedges of $1.8 million.

EAC expects to reclassify $0.7 million of deferred gains associated with ENP s interest rate swaps from AOCI to offset interest expense during the twelve months ending September 30, 2009. EAC also expects to reclassify $0.1 million of income taxes associated with ENP s interest rate swaps from AOCI to income tax benefit during the twelve months ending September 30, 2009.

Note 7. Fair Value Measurements

As discussed in Note 2. Basis of Presentation , EAC adopted SFAS 157 on January 1, 2008, as it relates to financial assets and liabilities. SFAS 157 establishes a fair value hierarchy that prioritizes the inputs used to measure fair value. The three levels of the fair value hierarchy defined by SFAS 157 are as follows:

Level 1 Unadjusted quoted prices are available in active markets for identical assets or liabilities.

Level 2 Pricing inputs, other than quoted prices within Level 1, that are either directly or indirectly observable.

Level 3 Pricing inputs that are unobservable requiring the use of valuation methodologies that result in management s best estimate of fair value.

EAC s assessment of the significance of a particular input to the fair value measurement requires judgment and may affect the valuation of the financial assets and liabilities and their placement within the fair value hierarchy levels. The following methods and assumptions were used to estimate the fair values of EAC s financial assets and liabilities that are accounted for at fair value on a recurring basis:

Level 2 Fair values of oil and natural gas swaps were estimated using a combined income and market-based valuation methodology based upon forward commodity price curves obtained from independent pricing services reflecting broker market quotes. Fair values of interest rate swaps were estimated using a combined income and market-based valuation

Table of Contents

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

methodology based upon credit ratings and forward interest rate yield curves obtained from independent pricing services reflecting broker market quotes.

Level 3 **-** Fair values of oil and natural gas floors and caps were estimated using pricing models and discounted cash flow methodologies based on inputs that are not readily available in public markets.

The following table sets forth EAC s financial assets and liabilities that were accounted for at fair value on a recurring basis as of September 30, 2008:

		Fair Value Measurements at Reporting Date Using		
Description	**September 30, 2008**	**Quoted Prices in Active Markets for Identical Assets (Level 1)**	**Significant Other Observable Inputs (Level 2)**	**Significant Unobservable Inputs (Level 3)**
			(in thousands)	
Oil derivative contracts swaps	$ (38,076)	$	$ (38,076)	$
Oil derivative contracts floors and caps	76,500			76,500
Natural gas derivative contracts swaps	1,347		1,347	
Natural gas derivative contracts floors and caps	6,911			6,911
Interest rate swaps	785		785	
Total	$ 47,467	$	$ (35,944)	$ 83,411

The following table summarizes the changes in the fair value of EAC s Level 3 financial assets and liabilities for the nine months ended September 30, 2008:

	Fair Value Measurements Using Significant Unobservable Inputs (Level 3)		
	Oil Derivative Contracts - Floors and Caps	**Natural Gas Derivative Contracts - Floors and Caps**	**Total**
		(in thousands)	
Balance at January 1, 2008	$ 16,647	$ 7,081	$ 23,728
Total gains (losses):			
Included in earnings	22,972	(3,845)	19,127
Purchases, issuances, and settlements	36,881	3,675	40,556

Balance at September 30, 2008	$ 76,500	$ 6,911	$ 83,411
The amount of total gains or losses for the period included in earnings attributable to the change in unrealized gains or losses relating to assets still held at the reporting date	$ 22,972	$ (3,845)	$ 19,127

Since EAC does not use hedge accounting for its commodity derivative contracts, all gains and losses on its Level 3 financial assets and liabilities are included in Derivative fair value loss (gain) in the accompanying Consolidated Statements of Operations. All fair values reflected in the tables above and in the accompanying Consolidated Balance Sheet have been adjusted for non-performance risk, resulting in a reduction of the net asset of approximately $1.1 million as of September 30, 2008.

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

Note 8. Asset Retirement Obligations

EAC s asset retirement obligations relate to future plugging and abandonment expenses on oil and natural gas properties and related facilities disposal. As of September 30, 2008 and December 31, 2007, EAC had $9.2 million and $6.7 million, respectively, held in escrow from which funds are released only for reimbursement of plugging and abandonment expenses on its Bell Creek properties, which is included in other long-term assets in the accompanying Consolidated Balance Sheets. The following table summarizes the changes in EAC s asset retirement obligations for the nine months ended September 30, 2008 (in thousands):

Future abandonment liability at January 1, 2008	$ 28,079
Wells drilled	287
Acquisition of properties	111
Accretion of discount	990
Plugging and abandonment costs incurred	(1,472)
Revision of previous estimates	5,250
Future abandonment liability at September 30, 2008	$ 33,245

As of September 30, 2008, $32.5 million of EAC s asset retirement obligations were long-term and recorded in Future abandonment cost, net of current portion and $0.8 million was current and included in Other current liabilities on the accompanying Consolidated Balance Sheets.

Note 9. Long-Term Debt

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

	Maturity Date	September 30, 2008	December 31, 2007
		(in thousands)	
Revolving credit facilities	3/7/2012	$ 622,939	$ 526,000
6.25% Senior Subordinated Notes	4/15/2014	150,000	150,000
6.0% Senior Subordinated Notes, net of unamortized discount of $4,082 and $4,440, respectively	7/15/2015	295,918	295,560
7.25% Senior Subordinated Notes, net of unamortized discount of $1,253 and $1,324, respectively	12/1/2017	148,747	148,676
Total		$ 1,217,604	$ 1,120,236

Encore Acquisition Company Senior Secured Credit Agreement

EAC is party to a five-year amended and restated credit agreement dated March 7, 2007 (as amended, the EAC Credit Agreement). Effective February 7, 2008, EAC amended the EAC Credit Agreement to, among other things, provide that certain negative covenants in the EAC Credit Agreement restricting hedge transactions do not apply to any oil and natural gas hedge transaction that is a floor or put transaction not requiring any future payments or delivery by EAC or any of its restricted subsidiaries. Effective May 22, 2008, EAC amended the EAC Credit Agreement to, among other things, increase the margins applicable to the ratio of total outstanding borrowings to borrowing base, as noted in the table below, and increase the borrowing base to $1.1 billion.

The following table represents the applicable margin for Eurodollar and base rate loans under the EAC Credit Agreement, as amended:

Ratio of Total Outstanding Borrowings to Borrowing Base	Applicable Margin for Eurodollar Loans	Applicable Margin for Base Rate Loans
Less than .50 to 1	1.250%	0.000%
Greater than or equal to .50 to 1 but less than .75 to 1	1.500%	0.250%
Greater than or equal to .75 to 1 but less than .90 to 1	1.750%	0.500%
Greater than or equal to .90 to 1	2.000%	0.750%

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

The aggregate amount of the commitments of the lenders under the EAC Credit Agreement is $1.25 billion. Availability under the EAC Credit Agreement is subject to a borrowing base, which is redetermined semi-annually and upon requested special redeterminations. As of September 30, 2008, the borrowing base was $1.1 billion and there were $482.9 million of outstanding borrowings and $617.1 million of borrowing capacity under the EAC Credit Agreement. As of September 30, 2008, EAC was in compliance with all covenants of the EAC Credit Agreement.

Encore Energy Partners Operating LLC Credit Agreement

OLLC is a party to a five-year credit agreement dated March 7, 2007 (as amended, the OLLC Credit Agreement). The aggregate amount of the commitments of the lenders under the OLLC Credit Agreement is $300 million. Availability under the OLLC Credit Agreement is subject to a borrowing base, which is redetermined semi-annually and upon requested special redeterminations. As of September 30, 2008, the borrowing base was $240 million and there were $140 million of outstanding borrowings, $0.1 million of outstanding letters of credit, and $99.9 million of borrowing capacity under the OLLC Credit Agreement. As of September 30, 2008, OLLC was in compliance with all covenants of the OLLC Credit Agreement.

Note 10. Stockholders Equity

In December 2007, EAC announced that its Board of Directors (the Board) approved a share repurchase program authorizing EAC to repurchase up to $50 million of its common stock. As of September 30, 2008, EAC had completed the share repurchase program by repurchasing and retiring 1,397,721 shares of its outstanding common stock at an average price of approximately $35.77 per share.

Note 11. Income Taxes

The components of income tax provision were as follows for the periods indicated:

	Nine months ended September 30, 2008	Nine months ended September 30, 2007
	(in thousands)	
Federal:		
Current	$ (6,693)	$ (116)
Deferred	(104,436)	(679)
Total federal	(111,129)	(795)
State, net of federal benefit/expense:		
Current	(2,249)	
Deferred	(5,217)	(695)
Total state	(7,466)	(695)
Income tax provision	$ (118,595)	$ (1,490)

The following table reconciles EAC s income tax provision with income tax at the Federal statutory rate for the periods indicated:

	Nine months ended September 30, 2008	Nine months ended September 30, 2007

	(in thousands)	
Income (loss) before income taxes, net of minority interest	$ 320,402	$ (782)
Income tax at the Federal statutory rate	$ (112,141)	$ 274
State income taxes, net of federal benefit/expense	(7,556)	19
Change in estimated future state tax rate	3	(597)
Nondeductible deferred compensation expense	(782)	(1,238)
Permanent and other	1,881	52
Income tax provision	$ (118,595)	$ (1,490)

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

At September 30, 2008, EAC had net operating loss (NOL) carryforwards of $22.4 million, which are available to offset future regular taxable income, if any. At September 30, 2008, EAC also had alternative minimum tax (AMT) credits of $2.7 million, which are available to reduce future regular tax liabilities in excess of AMT. EAC believes it is more likely than not that the NOL carryforwards will offset future taxable income prior to their expiration. The AMT credits have no expiration. Therefore, a valuation allowance against these deferred tax assets is not considered necessary.

As of September 30, 2008 and December 31, 2007, all of EAC s tax positions met the highly certain positions threshold prescribed by FIN No. 48, *Accounting for Uncertainty in Income Taxes - an Interpretation of FASB Statement No. 109* . As a result, no additional tax expense, interest, or penalties have been accrued. EAC includes interest assessed by taxing authorities and penalties related to income taxes in Other expense on its Consolidated Statements of Operations. For the nine months ended September 30, 2008, EAC recorded approximately $0.1 million of interest and penalties on certain tax positions. For the nine months ended September 30, 2007, EAC recorded only a nominal amount of interest and penalties on certain tax positions.

Note 12. EPS

The following table reflects EAC s EPS computations for the periods indicated:

	Three months ended September 30, 2008	Three months ended September 30, 2007	Nine months ended September 30, 2008	Nine months ended September 30, 2007
	(in thousands, except per share data)			
Numerator:				
Numerator for basic EPS:				
Net income (loss)	$ 206,307	$ 11,985	$ 201,807	$ (2,272)
Incremental minority interest from assumed conversion of ENP MIUs	(3,143)		(3,461)	
Numerator for diluted EPS	$ 203,164	$ 11,985	$ 198,346	$ (2,272)
Denominator:				
Denominator for basic EPS:				
Weighted average shares outstanding	52,258	53,198	52,466	53,140
Effect of dilutive options (a)	721	464	668	
Effect of dilutive restricted stock (b)	542	517	536	
Denominator for diluted EPS	53,521	54,179	53,670	53,140
Net income (loss) per common share:				
Basic	$ 3.95	$ 0.23	$ 3.85	$ (0.04)
Diluted	$ 3.80	$ 0.22	$ 3.70	$ (0.04)

(a) For the three months ended September 30, 2007, options to purchase 95,253 shares of common stock were outstanding but excluded from the diluted EPS calculations because their effect would have been antidilutive. For the nine months ended September 30, 2008 and 2007, options to purchase 40,551 and 1,422,350 shares of common stock, respectively, were outstanding but excluded from the diluted EPS calculations because their effect would have been antidilutive.

(b) For the three months ended September 30, 2008, 821 shares of restricted stock were outstanding but excluded from the diluted EPS calculations because their effect would have been antidilutive. For the nine months ended September 30, 2008 and 2007, 1,068 and 991,334 shares of restricted stock, respectively, were outstanding but excluded from the diluted EPS calculations because their effect would have been antidilutive.

Note 13. Incentive Stock Plans

In May 2008, EAC s stockholders approved the 2008 Incentive Stock Plan (the 2008 Plan). No additional awards will be granted under EAC s 2000 Incentive Stock Plan (the 2000 Plan) and any previously granted awards currently outstanding under the 2000 Plan will remain outstanding in accordance with their terms. The purpose of the 2008 Plan is to attract, motivate, and retain selected employees of EAC and to provide EAC 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 EAC and its subsidiaries and affiliates are eligible to be granted awards under the 2008 Plan. The total number of shares of common stock reserved for issuance pursuant to the 2008 Plan is 2,400,000. No more than 1,600,000 shares of EAC s common stock will be

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

available for grants of full value stock awards, such as restricted stock or stock units. As of September 30, 2008, there were 2,389,000 shares available for issuance under the 2008 Plan. Shares delivered or withheld for payment of the exercise price of an option, shares withheld for payment of tax withholding, shares subject to options or other awards that expire or are forfeited, and restricted shares that are forfeited will again become available for issuance under the 2008 Plan. The 2008 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 whose sole member is Jon S. Brumley, EAC s Chief Executive Officer and President. The Restricted Stock Award Committee may grant up to 25,000 shares of restricted stock on an annual basis to non-executive employees at its discretion.

The 2008 Plan contains the following individual limits:

- an employee may not be granted awards covering or relating to more than 300,000 shares of common stock during any calendar year;

- a non-employee director may not be granted awards covering or relating to more than 20,000 shares of common stock during 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 $5.0 million.

In May 2008, the Board approved certain amendments to the 2000 Plan to ensure compliance with Section 409A of the Code. In particular, the 2000 Plan was amended to allow for the exemption of options from the requirements of Section 409A of the Code by requiring that, upon a change-in-control, options granted or that vest on or after January 1, 2005 be valued at their fair market value as of the date they are cashed out, rather than the highest price per share paid in the 60 days prior to the change-in-control. The amendments to the 2000 Plan did not require stockholder approval under its terms, applicable laws, or the rules of the New York Stock Exchange.

The non-cash equity-based compensation expense recorded in the accompanying Consolidated Statements of Operations for the nine months ended September 30, 2008 and 2007 was $6.5 million and $7.0 million, respectively. The income tax benefit of the non-cash equity-based compensation expense recorded in the accompanying Consolidated Statements of Operations for the nine months ended September 30, 2008 and 2007 was $2.4 million and $2.6 million, respectively. During the nine months ended September 30, 2008 and 2007, EAC also capitalized $1.7 million and $0.9 million, respectively, of non-cash equity-based compensation cost as a component of Properties and equipment in the accompanying Consolidated Balance Sheets. Non-cash equity-based compensation expense has been allocated to LOE and general and administrative (G&A) expense based on the allocation of the respective employees cash compensation.

See Note 18. ENP for a discussion of ENP s equity-based compensation plan.

Stock Options

All options have a strike price equal to the fair market value of EAC s common stock on the grant date, have a ten-year life, and vest over a three-year period. The fair value of options granted during the nine months ended September 30, 2008 and 2007 was estimated on the grant date using a Black-Scholes option valuation model based on the assumptions noted in the following table. The expected volatility was based on the historical volatility of EAC s common stock for a period of time commensurate with the expected term of the options. For options granted prior to January 1, 2008, EAC used the simplified method prescribed by SAB No. 107, *Valuation of Share-Based Payment Arrangements for Public Companies* 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. For options granted subsequent to December 31, 2007, EAC determined the expected life of the options based on an analysis of historical exercise and forfeiture behavior as well as expectations about future behavior. The risk-free interest rate is based on the U.S Treasury yield curve in effect at the grant date for a period of time commensurate with the expected term of the options.

	Nine months ended September 30,	
	2008	2007
Expected volatility	33.7%	35.7%
Expected dividend yield	0.0%	0.0%
Expected term (in years)	6.25	6.00
Risk-free interest rate	3.0%	4.8%

Table of Contents

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

The following table summarizes the changes in EAC s outstanding options during the nine months ended September 30, 2008:

	Number of Options	Weighted Average Strike Price	Weighted Average Remaining Contractual Term	Aggregate Intrinsic Value (in thousands)
Outstanding at January 1, 2008	1,381,782	$16.03		
Granted	176,170	33.76		
Forfeited or expired	(13,304)	30.83		
Exercised	(45,616)	14.11		
Outstanding at September 30, 2008	1,499,032	18.04	5.4	$35,591
Exercisable at September 30, 2008	1,177,015	14.65	4.4	31,936

The weighted average fair value per share of options granted during the nine months ended September 30, 2008 and 2007 was $13.15 and $11.16, respectively. The total intrinsic value of options exercised during the nine months ended September 30, 2008 and 2007 was $1.6 million and $1.3 million, respectively. During the nine months ended September 30, 2008 and 2007, EAC received proceeds from the exercise of stock options of $0.5 million and $1.0 million, respectively, and recognized tax benefits related to stock options of $0.5 million and $0.4 million, respectively. At September 30, 2008, EAC had $1.6 million of total unrecognized compensation cost related to unvested stock options, which is expected to be recognized over a weighted average period of 2.0 years.

Restricted Stock

Restricted stock awards vest over varying periods from one to five years, subject to performance-based vesting for certain members of senior management. During the nine months ended September 30, 2008 and 2007, EAC recognized expense related to restricted stock of $5.5 million and $5.8 million, respectively, and recognized tax benefits related to restricted stock of $2.0 million and $2.2 million, respectively. The following table summarizes the changes in the number of EAC s unvested restricted stock awards and their related weighted average grant date fair value for the nine months ended September 30, 2008:

	Number of Shares	Weighted Average Grant Date Fair Value
Outstanding at January 1, 2008	918,338	$27.07
Granted	314,086	37.02
Vested	(235,086)	26.37
Forfeited	(33,162)	29.42
Outstanding at September 30, 2008	964,176	30.29

As of September 30, 2008, there were 896,937 shares of unvested restricted stock the vesting of which is dependent only on the passage of time and continued employment, 237,754 shares of which were granted during 2008. Additionally, as of September 30, 2008, there were 67,239 shares of unvested restricted stock the vesting of which is dependent not only on the passage of time and continued employment, but also on the achievement of certain performance measures, all of which were granted during 2008.

As of September 30, 2008, EAC had $10.5 million of total unrecognized compensation cost related to unvested restricted stock, which is expected to be recognized over a weighted average period of 2.8 years. None of EAC s unvested restricted stock is subject to variable accounting. During the nine months ended September 30, 2008 and 2007, there were 235,086 shares and 118,273 shares, respectively, of restricted stock that vested for which certain employees elected to satisfy minimum tax withholding obligations related thereto by directing EAC to withhold 28,193 shares and 5,545 shares of common stock, respectively. EAC accounts for these shares as treasury stock until they are formally retired and have been reflected as such in

Table of Contents

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

the accompanying consolidated financial statements.

Note 14. Comprehensive Income

The components of comprehensive income, net of tax, were as follows for the periods indicated:

	Three months ended September 30,		Nine months ended September 30,	
	2008	2007	2008	2007
	(in thousands)			
Net income (loss)	$ 206,307	$ 11,985	$ 201,807	$ (2,272)
Amortization of deferred loss on commodity derivative contracts		8,596	1,786	25,150
Change in deferred hedge gain (loss) on interest rate swaps	(264)		153	
Comprehensive income	$ 206,043	$ 20,581	$ 203,746	$ 22,878

Note 15. Financial Statements of Subsidiary Guarantors

In February 2007, EAC formed certain non-guarantor subsidiaries in connection with the formation of ENP. See Note 18. ENP for additional discussion of ENP s formation and other matters. As of September 30, 2008 and December 31, 2007, certain of EAC s wholly owned subsidiaries were subsidiary guarantors of EAC s senior subordinated notes. The subsidiary guarantees are full and unconditional, and joint and several. The subsidiary guarantors may, without restriction, transfer funds to EAC in the form of cash dividends, loans, and advances. In accordance with SEC rules, EAC has prepared condensed consolidating financial statements in order to quantify the financial position, results of operations, and cash flows of the subsidiary guarantors. The following Condensed Consolidating Balance Sheets as of September 30, 2008 and December 31, 2007, Condensed Consolidating Statements of Operations and Comprehensive Income (Loss) for the three and nine months ended September 30, 2008 and 2007, and Condensed Consolidating Statements of Cash Flows for the nine months ended September 30, 2008 and 2007 present consolidating financial information for Encore Acquisition Company (the Parent) on a stand alone, unconsolidated basis, and its combined guarantor and combined non-guarantor subsidiaries. As of September 30, 2008, EAC s guarantor subsidiaries were:

EAP Properties, Inc.;

EAP Operating, LLC;

Encore Operating; and

Encore Operating Louisiana, LLC.

As of September 30, 2008, EAC s non-guarantor subsidiaries were:

ENP;

OLLC;

Encore Partners GP Holdings LLC;

Encore Partners LP Holdings LLC;

GP LLC;

Encore Energy Partners Finance Corporation; and

Encore Clear Fork Pipeline LLC.

All intercompany investments in, loans due to/from, subsidiary equity, and revenues and expenses between the Parent, guarantor subsidiaries, and non-guarantor subsidiaries are shown prior to consolidation with the Parent and then eliminated to arrive at consolidated totals per the accompanying consolidated financial statements of EAC.

Table of Contents

ENCORE ACQUISITION COMPANY
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS Continued
(unaudited)
CONDENSED CONSOLIDATING BALANCE SHEET
September 30, 2008
(in thousands)

	Parent	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Eliminations	Consolidated Total
ASSETS					
Current assets:					
Cash and cash equivalents	$ 978	$ 2,692	$ 157	$	$ 3,827
Other current assets	44,554	223,395	42,582	(3,685)	306,846
Total current assets	45,532	226,087	42,739	(3,685)	310,673
Properties and equipment, at cost successful efforts method:					
Proved properties, including wells and related equipment		2,786,223	519,047		3,305,270
Unproved properties		129,437	78		129,515
Accumulated depletion, depreciation, and amortization		(579,638)	(90,448)		(670,086)
		2,336,022	428,677		2,764,699
Other property and equipment, net		10,134	610		10,744
Other assets, net	13,518	163,376	23,131		200,025
Investment in subsidiaries	2,561,942	(39,046)		(2,522,896)	
Total assets	$ 2,620,992	$ 2,696,573	$ 495,157	$ (2,526,581)	$ 3,286,141
LIABILITIES AND STOCKHOLDERS EQUITY					
Current liabilities	$ 12,781	$ 277,731	$ 38,990	$ (3,685)	$ 325,817
Deferred taxes	416,396		132		416,528
Long-term debt	1,077,604		140,000		1,217,604
Other liabilities		53,681	33,119		86,800
Total liabilities	1,506,781	331,412	212,241	(3,685)	2,046,749
Commitments and contingencies (see Note 16)					
Minority interest in consolidated partnership			125,181		125,181
Total stockholders equity	1,114,211	2,365,161	157,735	(2,522,896)	1,114,211

Total liabilities and stockholders equity	$ 2,620,992	$ 2,696,573	$ 495,157	$ (2,526,581)	$ 3,286,141

19

Table of Contents

ENCORE ACQUISITION COMPANY
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS Continued
(unaudited)
CONDENSED CONSOLIDATING BALANCE SHEET
December 31, 2007
(in thousands)

	Parent	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Eliminations	Consolidated Total
ASSETS					
Current assets:					
Cash and cash equivalents	$ 1	$ 1,700	$ 3	$	$ 1,704
Other current assets	535,221	437,852	21,053	(807,320)	186,806
Total current assets	535,222	439,552	21,056	(807,320)	188,510
Properties and equipment, at cost successful efforts method:					
Proved properties, including wells and related equipment		2,467,606	378,170		2,845,776
Unproved properties		63,352			63,352
Accumulated depletion, depreciation, and amortization		(451,343)	(37,661)		(489,004)
		2,079,615	340,509		2,420,124
Other property and equipment, net		10,610	407		11,017
Other assets, net	14,899	121,904	28,107		164,910
Investment in subsidiaries	2,090,471	20,611		(2,111,082)	
Total assets	$ 2,640,592	$ 2,672,292	$ 390,079	$ (2,918,402)	$ 2,784,561
LIABILITIES AND STOCKHOLDERS EQUITY					
Current liabilities	$ 306,787	$ 687,351	$ 17,885	$ (807,293)	$ 204,730
Deferred taxes	312,914				312,914
Long-term debt	1,072,736		47,500		1,120,236
Other liabilities		49,461	26,531		75,992
Total liabilities	1,692,437	736,812	91,916	(807,293)	1,713,872
Commitments and contingencies (see Note 16)					
Minority interest in consolidated partnership			122,534		122,534
Total stockholders equity	948,155	1,935,480	175,629	(2,111,109)	948,155

Total liabilities and stockholders equity	$ 2,640,592	$ 2,672,292	$ 390,079	$ (2,918,402)	$ 2,784,561

Table of Contents

ENCORE ACQUISITION COMPANY
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS Continued
(unaudited)
CONDENSED CONSOLIDATING STATEMENT OF OPERATIONS AND COMPREHENSIVE INCOME
For the Three Months Ended September 30, 2008
(in thousands)

	Parent	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Eliminations	Consolidated Total
Revenues:					
Oil	$	$ 224,101	$ 44,442	$	$ 268,543
Natural gas		56,956	9,816		66,772
Marketing		718	1,445		2,163
Total revenues		281,775	55,703		337,478
Expenses:					
Production:					
Lease operations		40,124	8,842		48,966
Production, ad valorem, and severance taxes		27,609	5,741		33,350
Depletion, depreciation, and amortization		49,481	9,064		58,545
Impairment of long-lived assets		26,292			26,292
Exploration		13,335	46		13,381
General and administrative	4,723	9,050	2,600	(1,070)	15,303
Marketing		539	1,316		1,855
Derivative fair value gain		(168,992)	(70,443)		(239,435)
Other operating	41	3,688	344		4,073
Total expenses	4,764	1,126	(42,490)	(1,070)	(37,670)
Operating income (loss)	(4,764)	280,649	98,193	1,070	375,148
Other income (expenses):					
Interest	(16,357)		(1,767)		(18,124)
Equity income from subsidiaries	347,114	32,564		(379,678)	
Other	78	2,535	10	(1,070)	1,553
Total other income (expenses)	330,835	35,099	(1,757)	(380,748)	(16,571)
Income before income taxes and minority interest	326,071	315,748	96,436	(379,678)	358,577
Income tax benefit (provision)	(120,943)	81	(322)		(121,184)
				(31,086)	(31,086)

Minority interest in income of consolidated partnership					
Net income	205,128	315,829	96,114	(410,764)	206,307
Change in deferred hedge gain on interest rate swaps, net of tax	150		(414)		(264)
Comprehensive income	$ 205,278	$ 315,829	$ 95,700	$ (410,764)	$ 206,043

21

Table of Contents

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

	Parent	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Eliminations	Consolidated Total
Revenues:					
Oil	$	$ 141,185	$ 18,110	$	$ 159,295
Natural gas		29,523	2,916		32,439
Marketing		1,148	2,134		3,282
Total revenues		171,856	23,160		195,016
Expenses:					
Production:					
Lease operations		32,722	4,392		37,114
Production, ad valorem, and severance taxes		17,432	2,571		20,003
Depletion, depreciation, and amortization		40,668	8,358		49,026
Exploration		8,914	6		8,920
General and administrative	20	6,072	6,576		12,668
Marketing		2,789	1,300		4,089
Derivative fair value loss		12,797	2,989		15,786
Other operating	41	6,073	237		6,351
Total expenses	61	127,467	26,429		153,957
Operating income (loss)	(61)	44,389	(3,269)		41,059
Other income (expenses):					
Interest	(10,601)	(14,052)	(4,829)	5,549	(23,933)
Equity income from subsidiaries	25,775			(25,775)	
Other	2,794	3,565	47	(5,549)	857
Total other income (expenses)	17,968	(10,487)	(4,782)	(25,775)	(23,076)
Income (loss) before income taxes and minority interest	17,907	33,902	(8,051)	(25,775)	17,983
Income tax provision	(8,910)	(61)	(15)		(8,986)
	2,988				2,988

Minority interest in loss of consolidated partnership					
Net income (loss)	11,985	33,841	(8,066)	(25,775)	11,985
Amortization of deferred loss on commodity derivative contracts, net of tax	(4,801)	13,397			8,596
Comprehensive income (loss)	$ 7,184	$ 47,238	$ (8,066)	$ (25,775)	$ 20,581

Table of Contents

ENCORE ACQUISITION COMPANY
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS Continued
(unaudited)
CONDENSED CONSOLIDATING STATEMENT OF OPERATIONS AND COMPREHENSIVE INCOME
For the Nine Months Ended September 30, 2008
(in thousands)

	Parent	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Eliminations	Consolidated Total
Revenues:					
Oil	$	$ 647,223	$ 128,778	$	$ 776,001
Natural gas		154,347	28,626		182,973
Marketing		3,533	5,207		8,740
Total revenues		805,103	162,611		967,714
Expenses:					
Production:					
Lease operations		108,191	21,822		130,013
Production, ad valorem, and severance taxes		79,524	16,321		95,845
Depletion, depreciation, and amortization		131,715	27,399		159,114
Impairment of long-lived assets		26,292			26,292
Exploration		30,349	113		30,462
General and administrative	11,668	19,630	8,455	(3,204)	36,549
Marketing		4,044	5,318		9,362
Derivative fair value loss		60,521	21,572		82,093
Other operating	124	8,655	1,026		9,805
Total expenses	11,792	468,921	102,026	(3,204)	579,535
Operating income (loss)	(11,792)	336,182	60,585	3,204	388,179
Other income (expenses):					
Interest	(49,353)		(5,316)		(54,669)
Equity income from subsidiaries	378,946	18,724		(397,670)	
Other	30	6,172	92	(3,204)	3,090
Total other income (expenses)	329,623	24,896	(5,224)	(400,874)	(51,579)
Income before income taxes and minority interest	317,831	361,078	55,361	(397,670)	336,600
Income tax provision	(118,435)		(160)		(118,595)
				(16,198)	(16,198)

Minority interest in income of consolidated partnership					
Net income	199,396	361,078	55,201	(413,868)	201,807
Amortization of deferred loss on commodity derivative contracts, net of tax	(1,071)	2,857			1,786
Change in deferred hedge gain on interest rate swaps, net of tax	(103)		256		153
Comprehensive income	$ 198,222	$ 363,935	$ 55,457	$ (413,868)	$ 203,746

23

Table of Contents

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

	Parent	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Eliminations	Consolidated Total
Revenues:					
Oil	$	$ 338,935	$ 38,579	$	$ 377,514
Natural gas		101,728	8,820		110,548
Marketing		20,153	6,986		27,139
Total revenues		460,816	54,385		515,201
Expenses:					
Production:					
Lease operations		95,843	9,343		105,186
Production, ad valorem, and severance taxes		45,893	5,857		51,750
Depletion, depreciation, and amortization		117,602	18,770		136,372
Exploration		23,847	9		23,856
General and administrative	57	18,491	7,668		26,216
Marketing		21,952	5,655		27,607
Derivative fair value loss		58,680	9,486		68,166
Other operating	124	13,018	525		13,667
Total expenses	181	395,326	57,313		452,820
Operating income (loss)	(181)	65,490	(2,928)		62,381
Other income (expenses):					
Interest	(63,182)	(6,415)	(11,273)	12,830	(68,040)
Equity income from subsidiaries	53,098			(53,098)	
Other	6,419	8,226	74	(12,830)	1,889
Total other income (expenses)	(3,665)	1,811	(11,199)	(53,098)	(66,151)
Income (loss) before income taxes and minority interest	(3,846)	67,301	(14,127)	(53,098)	(3,770)
Income tax provision	(1,414)	(22)	(54)		(1,490)
	2,988				2,988

Minority interest in loss of consolidated partnership					
Net income (loss)	(2,272)	67,279	(14,181)	(53,098)	(2,272)
Amortization of deferred loss on commodity derivative contracts, net of tax	(15,041)	40,191			25,150
Comprehensive income (loss)	$ (17,313)	$ 107,470	$ (14,181)	$ (53,098)	$ 22,878

24

Table of Contents

ENCORE ACQUISITION COMPANY
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS Continued
(unaudited)
CONDENSED CONSOLIDATING STATEMENT OF CASH FLOWS
For the Nine Months Ended September 30, 2008
(in thousands)

	Parent	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Eliminations	Consolidated Total
Cash flows from operating activities:					
Net cash provided by operating activities	$ 289,310	$ 141,580	$ 98,097	$	$ 528,987
Cash flows from investing activities:					
Acquisition of oil and natural gas properties		(116,679)	(88)		(116,767)
Development of oil and natural gas properties		(369,396)	(15,468)		(384,864)
Investments in subsidiaries	(259,105)			259,105	
Other		(34,161)	(302)		(34,463)
Net cash used in investing activities	(259,105)	(520,236)	(15,858)	259,105	(536,094)
Cash flows from financing activities:					
Repurchase of common stock	(50,000)				(50,000)
Proceeds from long-term debt, net of issuance costs	864,969		205,269		1,070,238
Payments on long-term debt	(861,500)		(113,000)		(974,500)
Net equity distributions		383,823	(124,718)	(259,105)	
Other	17,303	(4,175)	(49,636)		(36,508)
Net cash provided by (used in) financing activities	(29,228)	379,648	(82,085)	(259,105)	9,230
Increase in cash and cash equivalents	977	992	154		2,123
Cash and cash equivalents, beginning of period	1	1,700	3		1,704
Cash and cash equivalents, end of period	$ 978	$ 2,692	$ 157	$	$ 3,827

CONDENSED CONSOLIDATING STATEMENT OF CASH FLOWS
For the Nine Months Ended September 30, 2007
(in thousands)

	Parent	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Eliminations	Consolidated Total
Cash flows from operating activities:					
Net cash provided by operating activities	$	$ 199,333	$ 14,311	$	$ 213,644
Cash flows from investing activities:					
Proceeds from disposition of assets		291,339			291,339
Acquisition of oil and natural gas properties		(509,630)	(330,315)		(839,945)
Development of oil and natural gas properties		(256,797)	(2,660)		(259,457)
Investments in subsidiaries	(400,158)			400,158	
Other		(25,013)	(74)		(25,087)
Net cash used in investing activities	(400,158)	(500,101)	(333,049)	400,158	(833,150)
Cash flows from financing activities:					
Proceeds from issuance of ENP common units, net of issuance costs			171,220		171,220
Proceeds from long-term debt, net of issuance costs	1,020,533		248,758		1,269,291
Payments on long-term debt	(621,428)		(184,000)		(805,428)
Net equity contributions		306,500	93,658	(400,158)	
Other	1,053	(5,142)	(3,784)		(7,873)
Net cash provided by financing activities	400,158	301,358	325,852	(400,158)	627,210
Increase in cash and cash equivalents		590	7,114		7,704
Cash and cash equivalents, beginning of period		763			763
Cash and cash equivalents, end of period	$	$ 1,353	$ 7,114	$	$ 8,467

Table of Contents

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

Note 16. Commitments and Contingencies

Litigation

EAC 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 EAC s business, financial position, results of operations, or liquidity.

Additionally, EAC has contractual obligations related to future plugging and abandonment expenses on oil and natural gas properties and related facilities disposal, long-term debt, derivative contracts, capital and operating leases, and development commitments. See the contractual obligations and commitments table included in Item 2. Management s Discussion and Analysis of Financial Condition and Results of Operations of this Report for contractual obligations as of September 30, 2008.

ExxonMobil

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

In July 2008, EAC earned the right to participate in all fields by drilling the final well of the 24-well commitment phase and is entitled to a 30 percent working interest in future drilling locations. EAC has the right to propose and drill wells for as long as it is engaged in continuous drilling operations.

During the nine months ended September 30, 2008 and 2007, EAC advanced $41.2 million and $30.8 million, respectively, to ExxonMobil for its portion of costs incurred drilling wells under the joint development agreement. At September 30, 2008, EAC had a net receivable from ExxonMobil of $86.7 million, of which $12.2 million was included in Accounts receivable, net and $74.5 million was included in Long-term receivables on the accompanying Consolidated Balance Sheet based on when EAC expects repayment. At December 31, 2007, EAC had a net receivable from ExxonMobil of $51.7 million, of which $12.3 million was included in Accounts receivable, net and $39.4 million was included in Long-term receivables on the accompanying Consolidated Balance Sheet.

Note 17. Related Party Transactions

During the three and nine months ended September 30, 2008, EAC received approximately $51.5 million and $132.3 million, respectively, from affiliates of Tesoro Corporation (Tesoro) related to gross production sold from wells operated by Encore Operating. During the three and nine months ended September 30, 2007, EAC received approximately $28.5 million and $47.2 million, respectively, from Tesoro related to gross production sold from wells operated by Encore Operating. Mr. John V. Genova, a member of the Board, served as an employee of Tesoro until May 2008.

See Note 18. ENP for a discussion of related party transactions with ENP.

Note 18. ENP

Administrative Services Agreement

ENP does not have any employees. The employees supporting ENP s operations are employees of EAC. Accordingly, EAC recognizes all employee-related expenses and liabilities in its consolidated financial statements. In connection with the closing of ENP s IPO, EAC entered into an amended and restated administrative services agreement (the Administrative Services Agreement) with ENP, GP LLC, OLLC, and Encore Operating, whereby Encore Operating performs administrative services for ENP, such as accounting, corporate development, finance, land, legal, and engineering. In addition, Encore Operating provides all personnel and any facilities, goods, and equipment necessary to perform these services not otherwise provided by ENP. Encore Operating initially received an administrative fee of $1.75 per BOE of ENP s production for such services. Effective April 1, 2008, the administrative fee increased to $1.88 per BOE of ENP s production as a result of the COPAS Wage Index Adjustment. Encore Operating also charges ENP for reimbursement of actual third-party expenses incurred on ENP s behalf.

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

Encore Operating has substantial discretion in determining which third-party expenses to incur on ENP s behalf. In addition, Encore Operating is entitled to retain any COPAS overhead charges associated with drilling and operating wells that would otherwise be paid by non-operating interest owners to the operator of a well. Encore Operating is not liable to ENP for its performance of, or failure to perform, services under the Administrative Services Agreement unless its acts or omissions constitute gross negligence or willful misconduct.

ENP also reimburses EAC for any additional taxes paid by EAC resulting from the inclusion of ENP and its subsidiaries in consolidated tax returns with EAC and its subsidiaries as required by applicable law. The amount of any such reimbursement is limited to the tax that ENP and its subsidiaries would have paid had it not been included in a combined group with EAC.

Purchase and Investment Agreement

In December 2007, OLLC entered into a purchase and investment agreement with Encore Operating pursuant to which OLLC agreed to acquire certain oil and natural gas properties and related assets in the Permian and Williston Basins from Encore Operating. The transaction closed in February 2008, but was effective as of January 1, 2008. The consideration for the acquisition consisted of approximately $125.3 million in cash, including post-closing adjustments, and 6,884,776 common units representing limited partner interests in ENP. ENP funded the cash portion of the purchase price with borrowings under the OLLC Credit Agreement. EAC used the proceeds from the sale to reduce outstanding borrowings under the EAC Credit Agreement.

Long-Term Incentive Plan

In September 2007, GP LLC approved the Encore Energy Partners GP LLC Long-Term Incentive Plan (the ENP Plan), which provides for the granting of options, restricted units, phantom units, unit appreciation rights, distribution equivalent rights, other equity-based awards, and unit awards. All employees, consultants, and directors of EAC, GP LLC, and any of their subsidiaries and affiliates who perform services for ENP are eligible to be granted awards under the ENP Plan. The total number of common units reserved for issuance pursuant to the ENP Plan is 1,150,000. As of September 30, 2008, there were 1,125,000 common units available for issuance under the ENP Plan. The ENP Plan is administered by the board of directors of GP LLC or a committee thereof, referred to as the plan administrator.

In October 2007, ENP issued 20,000 phantom units to members of GP LLC s board of directors pursuant to the ENP Plan. In February 2008, ENP issued 5,000 phantom units to a new member of GP LLC s board of directors pursuant to the ENP Plan. A phantom unit entitles the grantee to receive a common unit upon the vesting of the phantom unit or, at the discretion of the plan administrator, cash equivalent to the value of a common unit. ENP intends to settle the phantom units at vesting by issuing common units; therefore, these phantom units are classified as equity instruments. The phantom units vest in four equal annual installments. The holders of phantom units are also entitled to receive distribution equivalent rights prior to vesting, which entitle them to receive cash equal to the amount of any cash distributions made by ENP with respect to a common unit during the period the right is outstanding. During the three and nine months ended September 30, 2008, ENP recognized non-cash equity-based compensation expense of approximately $45,000 and $0.2 million, respectively, for the phantom units, which is included in General and administrative expense in the accompanying Consolidated Statements of Operations. As of September 30, 2008, ENP had $0.3 million of total unrecognized compensation cost related to unvested phantom units, which is expected to be recognized over a weighted average period of 1.1 years.

To satisfy common unit awards under the ENP Plan, ENP may issue new common units, acquire common units in the open market, or use common units owned by EAC and its subsidiaries. As of September 30, 2008 there have been no additional issuances or forfeitures of awards under the ENP Plan.

Management Incentive Units (MIUs)

In May 2007, the board of directors of GP LLC issued 550,000 MIUs to certain executive officers of GP LLC. MIUs are a limited partner interest in ENP that entitles the holder to quarterly distributions to the extent paid to ENP s common unitholders and to increasing distributions upon the achievement of 10 percent compounding increases in ENP s distribution rate to common unitholders. MIUs are convertible into ENP common units upon the occurrence of any of the following events:

a change in control;

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

- at the option of the holder, when ENP s aggregate quarterly distributions to unitholders over four consecutive quarters are at least $2.05 per unit; or

- the holder s death or disability.

In order for distributions payable to the holders of MIUs to increase, the distributions payable to common unitholders must increase by 10 percent on a compounded basis. MIUs are subject to a maximum limit on the aggregate number of common units issuable to, and the aggregate distributions payable to, holders of MIUs as follows:

- the holders of MIUs are not entitled to receive, in the aggregate, common units upon conversion of the MIUs that exceed a maximum limit of 5.1 percent of ENP s then-outstanding units; and

- the holders of MIUs are not entitled to receive, in the aggregate, distributions of ENP s available cash in an amount that exceeds a maximum limit of 5.1 percent of all such distributions to all unitholders at the time of any such distribution.

The holders of MIUs do not have voting rights with respect to the MIUs.

The MIUs vest in three equal annual installments, with the first installment vesting upon the closing of the IPO. For the three and nine months ended September 30, 2008, ENP recognized total non-cash equity-based compensation expense for the MIUs of $1.1 million and $3.2 million, respectively, which has been allocated to LOE and G&A expense based on the allocation of the respective employees cash compensation. During each of the three and nine months ended September 30, 2007, ENP recognized total non-cash equity-based compensation expense for the MIUs of $5.7 million, which is included in General and administrative expense in the accompanying Consolidated Statements of Operations. As of September 30, 2008, ENP had $1.6 million of total unrecognized compensation cost related to unvested MIUs, which is expected to be recognized over a weighted average period of 0.5 years. For the fourth quarter of 2008 through the third quarter of 2009, the expense will be approximately $0.4 million per quarter. There have been no additional issuances or forfeitures of MIUs.

Distributions

In January 2008, ENP announced a cash distribution for the fourth quarter of 2007 to unitholders of record as of the close of business on February 6, 2008 at a rate of $0.3875 per unit. Approximately $9.8 million was paid on February 14, 2008, $5.6 million of which was paid to EAC and its subsidiaries and had no impact on EAC s consolidated cash.

In May 2008, ENP announced a cash distribution for the first quarter of 2008 to unitholders of record as of the close of business on May 9, 2008 at a rate of $0.5755 per unit. Approximately $19.3 million was paid on May 15, 2008, $12.3 million of which was paid to EAC and its subsidiaries and had no impact on EAC s consolidated cash.

In August 2008, ENP announced a cash distribution for the second quarter of 2008 to unitholders of record as of the close of business on August 11, 2008 at a rate of $0.6881 per unit. Approximately $23.1 million was paid on August 14, 2008, $14.7 million of which was paid to EAC and its subsidiaries and had no impact on EAC s consolidated cash.

Table of Contents

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

Note 19. Segment Information

EAC operates in only one industry: the oil and natural gas exploration and production industry in the United States. However, EAC is organizationally structured along two reportable segments: EAC Standalone and ENP. EAC s segments are components of its business for which separate financial information related to operating and development costs are available and regularly evaluated by the chief operating decision maker in deciding how to allocate capital resources to projects and in assessing performance. The accounting policies used in the generation of segment financial statements are the same as those described in Note 2. Summary of Significant Accounting Policies in EAC s 2007 Annual Report on Form 10-K. Prior to the fourth quarter of 2007, segment reporting was not applicable to EAC.

The following tables provide EAC s operating segment information required by SFAS No. 131, *Disclosure about Segments of an Enterprise and Related Information* .

	For the Three Months Ended September 30, 2008			
	EAC Standalone	ENP	Eliminations	Consolidated Total
	(in thousands)			
Revenues:				
Oil	$ 224,101	$ 44,442	$	$ 268,543
Natural gas	56,956	9,816		66,772
Marketing	718	1,445		2,163
Total revenues	281,775	55,703		337,478
Expenses:				
Production:				
Lease operations	40,124	8,842		48,966
Production, ad valorem, and severance taxes	27,609	5,741		33,350
Depletion, depreciation, and amortization	49,481	9,064		58,545
Impairment of long-lived assets	26,292			26,292
Exploration	13,335	46		13,381
General and administrative	13,776	2,597	(1,070)	15,303
Marketing	539	1,316		1,855
Derivative fair value gain	(168,992)	(70,443)		(239,435)
Other operating	3,729	344		4,073
Total expenses	5,893	(42,493)	(1,070)	(37,670)
Operating income	275,882	98,196	1,070	375,148
Other income (expenses):				
Interest	(16,357)	(1,767)		(18,124)
Other	2,613	10	(1,070)	1,553

Total other expenses	(13,744)	(1,757)	(1,070)	(16,571)
Income before income taxes and minority interest	262,138	96,439		358,577
Income tax provision	(120,862)	(322)		(121,184)
Minority interest in income of consolidated partnership	(31,086)			(31,086)
Net income	110,190	96,117		206,307
Change in deferred hedge gain on interest rate swaps, net of tax	333	(597)		(264)
Comprehensive income	$ 110,523	$ 95,520	$	$ 206,043
Segment assets (as of September 30, 2008)	$ 2,791,848	$ 495,157	$ (864)	$ 3,286,141

29

Table of Contents

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

	For the Nine Months Ended September 30, 2008			
	EAC Standalone	ENP	Eliminations	Consolidated Total
	(in thousands)			
Revenues:				
Oil	$ 647,223	$ 128,778	$	$ 776,001
Natural gas	154,347	28,626		182,973
Marketing	3,533	5,207		8,740
Total revenues	805,103	162,611		967,714
Expenses:				
Production:				
Lease operations	108,191	21,822		130,013
Production, ad valorem, and severance taxes	79,524	16,321		95,845
Depletion, depreciation, and amortization	131,715	27,399		159,114
Impairment of long-lived assets	26,292			26,292
Exploration	30,349	113		30,462
General and administrative	31,301	8,452	(3,204)	36,549
Marketing	4,044	5,318		9,362
Derivative fair value loss	60,521	21,572		82,093
Other operating	8,779	1,026		9,805
Total expenses	480,716	102,023	(3,204)	579,535
Operating income	324,387	60,588	3,204	388,179
Other income (expenses):				
Interest	(49,353)	(5,316)		(54,669)
Other	6,202	92	(3,204)	3,090
Total other expenses	(43,151)	(5,224)	(3,204)	(51,579)
Income before income taxes and minority interest	281,236	55,364		336,600
Income tax provision	(118,435)	(160)		(118,595)
Minority interest in income of consolidated partnership	(16,198)			(16,198)
Net income	146,603	55,204		201,807

Amortization of deferred loss on commodity derivative contracts, net of tax	1,786			1,786
Change in deferred hedge gain on interest rate swaps, net of tax	(234)	387		153
Comprehensive income	$ 148,155	$ 55,591	$	$ 203,746

Note 20. Impairment of Long-Lived Assets

During the third quarter of 2008, circumstances indicated that the carrying value of the two wells EAC has drilled in the Tuscaloosa Marine Shale may not be recoverable. EAC compared the assets carrying value to the undiscounted expected future net cash flows, which indicated the need for an impairment charge. EAC then compared the net book value of the impaired assets to their estimated fair value, which resulted in a write-down of the value of proved oil and natural gas properties of $26.3 million. Fair value was determined using estimates of future production volumes and estimates of future prices EAC might receive for these volumes, discounted to a present value.

Note 21. Subsequent Events

On October 15, 2008, EAC announced that the Board authorized a new share repurchase program of up to $40 million of EAC s common stock. The shares may be repurchased from time to time in the open market or through privately negotiated transactions. The repurchase program is subject to business and market conditions, and may be suspended or discontinued at any time. The share repurchase program will be funded using EAC s available cash. As of October 29, 2008, EAC had repurchased and retired 620,265 shares of its outstanding common stock for approximately $17.2 million, or an average price of $27.68 per share, under the new share repurchase program.

Table of Contents

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

On October 28, 2008, the Board declared a dividend of one right for each outstanding share of EAC s common stock to stockholders of record at the close of business on November 7, 2008. Each right entitles the registered holder to purchase from EAC a unit consisting of one one-hundredth of a share of Series A Junior Participating Preferred Stock, par value $0.01 per share, at a purchase price of $120 per fractional share, subject to adjustment. The description and terms of the rights are set forth in a Rights Agreement dated as of October 28, 2008 between the Company and Mellon Investor Services LLC, as Rights Agent.

On October 28, 2008, ENP announced a cash distribution for the third quarter of 2008 to unitholders of record as of the close of business on November 7, 2008 at a rate of $0.66 per unit. Approximately $22.2 million is expected to be paid to unitholders on or about November 14, 2008, $14.1 million of which is expected to be paid to EAC and its subsidiaries and will have no impact on EAC s consolidated cash. Following the payment of this distribution by ENP, at the option of the holder, the MIUs will become convertible into ENP common units at a then-current ratio of one MIU to 3.118 ENP common units.

On October 31, 2008, ENP issued 25,000 phantom units to members of GP LLC s board of directors pursuant to the ENP Plan. The phantom units vest in four equal installments beginning on the first anniversary of the date of grant.

Table of Contents

ENCORE ACQUISITION COMPANY

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

The following discussion and analysis contains forward-looking statements, which give our current expectations or forecasts of future events. Actual results could differ materially from those stated in the forward-looking statements due to many factors, including, but not limited to, those set forth under Item 1A. Risk Factors in our 2007 Annual Report on Form 10-K. The following discussion and analysis 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 2007 Annual Report on Form 10-K.

Introduction

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

- Third Quarter 2008 Highlights
- Results of Operations
  - Comparison of Quarter Ended September 30, 2008 to Quarter Ended September 30, 2007
  - Comparison of Nine Months Ended September 30, 2008 to Nine Months Ended September 30, 2007
- Capital Commitments, Capital Resources, and Liquidity
- Critical Accounting Policies and Estimates
- New Accounting Pronouncements

Third Quarter 2008 Highlights

Our financial and operating results for the third quarter of 2008 included the following:

- Our oil and natural gas revenues increased 75 percent to $335.3 million as compared to $191.7 million in the third quarter of 2007 as a result of higher average realized prices and increased production volumes.
- Our average realized oil price increased 70 percent to $108.21 per Bbl as compared to $63.48 per Bbl in the third quarter of 2007. Our average realized natural gas price increased 57 percent to $9.57 per Mcf as compared to $6.09 per Mcf in the third quarter of 2007.
- Our average daily production volumes increased seven percent to 39,617 BOE/D as compared to 36,917 BOE/D in the third quarter of 2007. Oil represented 68 percent and 74 percent of our total production volumes in the third quarter of 2008 and 2007, respectively.
- We invested $256.5 million in oil and natural gas activities, of which $186.5 million was invested in development, exploitation, and exploration activities, yielding 76 gross (28.3 net) successful wells, and $70.0 million was invested in acquisitions.
- Our production margin (defined as oil and natural gas revenues less production expenses) increased 88 percent to $253.0 million as compared to $134.6 million in the third quarter of 2007. Total oil and natural gas revenues per BOE increased by 63 percent while total production expenses per BOE increased by 34 percent. On a per BOE basis, our production margin increased 75 percent to $69.42 per BOE as compared to $39.64 per BOE for the third quarter of 2007.
- We completed the commitment phase of our West Texas joint development agreement with ExxonMobil.
- We completed our previously announced $50 million stock repurchase program and on October 15, 2008, the Board approved an additional $40 million stock repurchase program.

32

Table of Contents

ENCORE ACQUISITION COMPANY

Results of Operations

Comparison of Quarter Ended September 30, 2008 to Quarter Ended September 30, 2007

Oil and natural gas revenues. The following table illustrates the components of oil and natural gas revenues for the periods indicated, as well as each period s respective production volumes and average prices:

	Three months ended September 30,		Increase / (Decrease)	
	2008	2007	$	%
Revenues (in thousands):				
Oil wellhead	$ 268,543	$ 170,118	*$ 98,425*	
Oil commodity derivative contracts		(10,823)	*10,823*	
Total oil revenues	$ 268,543	$ 159,295	*$ 109,248*	*69%*
Natural gas wellhead	$ 66,772	$ 35,012	*$ 31,760*	
Natural gas commodity derivative contracts		(2,573)	*2,573*	
Total natural gas revenues	$ 66,772	$ 32,439	*$ 34,333*	*106%*
Combined wellhead	$ 335,315	$ 205,130	*$ 130,185*	
Combined commodity derivative contracts		(13,396)	*13,396*	
Total combined oil and natural gas revenues	$ 335,315	$ 191,734	*$ 143,581*	*75%*
Average realized prices:				
Oil wellhead ($/Bbl)	$ 108.21	$ 67.80	*$ 40.41*	
Oil commodity derivative contracts ($/Bbl)		(4.32)	*4.32*	
Total oil revenues ($/Bbl)	$ 108.21	$ 63.48	*$ 44.73*	*70%*
Natural gas wellhead ($/Mcf)	$ 9.57	$ 6.58	*$ 2.99*	
Natural gas commodity derivative contracts ($/Mcf)		(0.49)	*0.49*	
Total natural gas revenues ($/Mcf)	$ 9.57	$ 6.09	*$ 3.48*	*57%*
Combined wellhead ($/BOE)	$ 92.00	$ 60.39	*$ 31.61*	
Combined commodity derivative contracts ($/BOE)		(3.94)	*3.94*	
Total combined oil and natural gas revenues ($/BOE)	$ 92.00	$ 56.45	*$ 35.55*	*63%*

Total production volumes:						
Oil (MBbls)		2,482		2,509	*(27)*	*-1%*
Natural gas (MMcf)		6,978		5,323	*1,655*	*31%*
Combined (MBOE)		3,645		3,396	*249*	*7%*
Average daily production volumes:						
Oil (Bbls/D)		26,975		27,275	*(300)*	*-1%*
Natural gas (Mcf/D)		75,847		57,857	*17,990*	*31%*
Combined (BOE/D)		39,617		36,917	*2,700*	*7%*
Average NYMEX prices:						
Oil (per Bbl)	$	118.67	$	75.17	*$ 43.50*	*58%*
Natural gas (per Mcf)	$	10.27	$	6.16	*$ 4.11*	*67%*

Oil revenues increased 69 percent from $159.3 million in the third quarter of 2007 to $268.5 million in the third quarter of 2008 as a result of an increase in our average realized oil price, partially offset by a decrease in oil production volumes of 27 MBbls, which reduced oil revenues by approximately $1.9 million. The decrease in oil production was primarily the result of plant and refinery shutdowns in the wake of Hurricane Ike.

Our average realized oil price increased $44.73 per Bbl primarily as a result of an increase in our wellhead price, which increased oil revenues by approximately $100.3 million, or $40.41 per Bbl. Our average oil wellhead price increased as a result of increases in the overall market price for oil, as reflected in the increase in the average NYMEX price from $75.17 per Bbl in the third quarter of 2007 to $118.67 Bbl in the third quarter of 2008. In addition, as a result of our discontinuance of hedge accounting in July 2006, oil revenues for the third quarter of 2007 included amortization of the effects of certain commodity derivative contracts that were previously designated as hedges of approximately $10.8 million, or $4.32 per Bbl.

ENCORE ACQUISITION COMPANY

Our oil wellhead revenue was reduced by $18.5 million and $9.8 million in the third quarter of 2008 and 2007, respectively, for NPI payments related to our CCA properties.

Natural gas revenues increased 106 percent from $32.4 million in the third quarter of 2007 to $66.8 million in the third quarter of 2008 as a result of an increase in our average realized natural gas price and an increase in production volumes of 1,655 MMcf, which increased natural gas revenues by approximately $10.9 million. The increase in natural gas production volumes was primarily the result of our development program.

Our average realized natural gas price increased $3.48 per Mcf primarily as a result of an increase in our wellhead price, which increased natural gas revenues by approximately $20.9 million, or $2.99 per Mcf. Our average natural gas wellhead price increased as a result of increases in the overall market price for natural gas, as reflected in the increase in the average NYMEX price from $6.16 per Mcf in the third quarter of 2007 to $10.27 per Mcf in the third quarter of 2008. In addition, as a result of our discontinuance of hedge accounting in July 2006, natural gas revenues for the third quarter of 2007 included amortization of the effects of commodity certain derivative contracts that were previously designated as hedges of approximately $2.6 million, or $0.49 per Mcf.

The table below illustrates the relationship between oil and natural gas wellhead prices as a percentage of average NYMEX prices for the periods indicated. Management uses the wellhead to NYMEX margin analysis to analyze trends in our oil and natural gas revenues.

	Three months ended September 30,	
	2008	**2007**
Oil wellhead ($/Bbl)	$ 108.21	$ 67.80
Average NYMEX ($/Bbl)	$ 118.67	$ 75.17
Differential to NYMEX	$ (10.46)	$ (7.37)
Oil wellhead to NYMEX percentage	91%	90%
Natural gas wellhead ($/Mcf)	$ 9.57	$ 6.58
Average NYMEX ($/Mcf)	$ 10.27	$ 6.16
Differential to NYMEX	$ (0.70)	$ 0.42
Natural gas wellhead to NYMEX percentage	93%	107%

Our oil wellhead price as a percentage of the average NYMEX price remained relatively constant at 91 percent in the third quarter of 2008 as compared to 90 percent in the third quarter of 2007. We expect our oil wellhead differentials to widen slightly in the fourth quarter of 2008 as compared to the third quarter of 2008, which is historically common.

Our natural gas wellhead price as a percentage of the average NYMEX price was 93 percent in the third quarter of 2008 as compared to 107 percent in the third quarter of 2007. Certain of our natural gas marketing contracts determine the price that we are paid based on the value of the dry gas sold plus a portion of the value of liquids extracted. Since title of the natural gas sold under these contracts passes at the inlet of the processing plant, we report inlet volumes of natural gas in Mcf as production. During the third quarter of 2007, the price of NGLs increased at a faster pace than did the price of natural gas. As a result, the price we were paid per Mcf for natural gas sold under certain contracts increased to a level above NYMEX. This resulted in a slight positive overall natural gas differential to NYMEX in the third quarter of 2007. During the third quarter of 2008, the differential narrowed, as compared to the third quarter of 2007, because of certain NGL pipeline constraints which resulted in a decrease in NGL sales. We expect our natural gas wellhead differentials to remain approximately constant or to widen slightly in the fourth quarter of 2008 as compared to the third quarter of 2008.

Table of Contents

ENCORE ACQUISITION COMPANY

Marketing revenues and expenses. The following table summarizes our marketing activities for the periods indicated:

	Three months ended September 30,		Increase / (Decrease)	
	2008	2007	$	%
	($ in thousands, except per BOE amounts)			
Marketing revenues	$ 2,163	$ 3,282	*$ (1,119)*	*-34%*
Marketing expenses	1,855	4,089	*(2,234)*	*-55%*
Marketing gain (loss)	$ 308	$ (807)	*$ 1,115*	*-138%*
Marketing revenues per BOE	$ 0.59	$ 0.97	*$ (0.38)*	*-39%*
Marketing expenses per BOE	0.51	1.21	*(0.70)*	*-58%*
Marketing gain (loss) per BOE	$ 0.08	$ (0.24)	*$ 0.32*	*-133%*

In 2007, we discontinued purchasing oil from third party companies as market conditions changed and pipeline space was gained. Implementing this change allowed us to focus on the marketing of our own oil production, leveraging newly gained pipeline space, and delivering oil to various newly developed markets in an effort to maximize the value of the oil at the wellhead.

In March 2007, ENP acquired a natural gas pipeline from Anadarko as part of the Big Horn Basin asset acquisition. Natural gas volumes are purchased from numerous gas producers at the inlet to the pipeline and resold downstream to various local and off-system markets.

Marketing expenses in the third quarter of 2008 include pipeline tariffs, storage, truck facility fees, and tank bottom costs used to support the sale of equity crude, the revenues of which are included in our oil revenues instead of marketing revenues.

Table of Contents

ENCORE ACQUISITION COMPANY

Expenses. The following table summarizes our expenses, excluding marketing expenses shown above, for the periods indicated:

	Three months ended September 30, 2008	Three months ended September 30, 2007	*Increase / (Decrease) $*	*%*
Expenses (in thousands):				
Production:				
Lease operations	$ 48,966	$ 37,114	*$ 11,852*	
Production, ad valorem, and severance taxes	33,350	20,003	*13,347*	
Total production expenses	82,316	57,117	*25,199*	*44%*
Other:				
Depletion, depreciation, and amortization	58,545	49,026	*9,519*	
Impairment of long-lived assets	26,292		*26,292*	
Exploration	13,381	8,920	*4,461*	
General and administrative	15,303	12,668	*2,635*	
Derivative fair value loss (gain)	(239,435)	15,786	*(255,221)*	
Other operating	4,073	6,351	*(2,278)*	
Total operating	(39,525)	149,868	*(189,393)*	*-126%*
Interest	18,124	23,933	*(5,809)*	
Income tax provision	121,184	8,986	*112,198*	
Total expenses	$ 99,783	$ 182,787	*$ (83,004)*	*-45%*
Expenses (per BOE):				
Production:				
Lease operations	$ 13.43	$ 10.93	*$ 2.50*	
Production, ad valorem, and severance taxes	9.15	5.89	*3.26*	
Total production expenses	22.58	16.82	*5.76*	*34%*
Other:				
Depletion, depreciation, and amortization	16.06	14.43	*1.63*	
Impairment of long-lived assets	7.21		*7.21*	
Exploration	3.67	2.63	*1.04*	
General and administrative	4.20	3.73	*0.47*	
Derivative fair value loss (gain)	(65.69)	4.65	*(70.34)*	
Other operating	1.12	1.87	*(0.75)*	
Total operating	(10.85)	44.13	*(54.98)*	*-125%*
Interest	4.97	7.05	*(2.08)*	
Income tax provision	33.25	2.65	*30.60*	
Total expenses	$ 27.37	$ 53.83	*$ (26.46)*	*-49%*

Production expenses. Total production expenses increased 44 percent from $57.1 million in the third quarter of 2007 to $82.3 million in the third quarter of 2008 as a result of a $5.76 increase in the per BOE rate and a seven percent increase in total production volumes.

Production expense attributable to LOE increased $11.9 million from $37.1 million in the third quarter of 2007 to $49.0 million in the third quarter of 2008 as a result of a $2.50 increase in the per BOE rate, which contributed approximately $9.1 million of additional LOE, and an increase in production volumes, which increased LOE by approximately $2.7 million. The increase in our LOE per BOE rate was attributable to:

- increases in prices paid to oilfield service companies and suppliers;
- increases in natural gas prices resulting in higher electricity costs and gas plant fuel costs;
- higher compensation levels for engineers and other technical professionals; and
- an increase of (1) approximately $1.01 per BOE for retention bonuses paid in August 2008 and (2) approximately $0.45 per BOE for retention bonuses to be paid in August 2009.

In May 2008, our Board approved a retention plan for all of our current employees, excluding members of our strategic

ENCORE ACQUISITION COMPANY

team, providing for the payment of four months of base salary or base rate of pay, as applicable, upon the completion of the strategic alternatives process, subject to continued employment. This bonus was paid in August 2008. In July 2008, our Board approved a separate retention plan for all of our then-current employees, excluding our Chairman and Chief Executive Officer, providing for the payment of eight months of base salary or base rate of pay, as applicable, in August 2009, subject to continued employment. We expect our LOE for the fourth quarter of 2008 to include approximately $0.67 per BOE for retention bonuses to be paid in August 2009.

Production expense attributable to production, ad valorem, and severance taxes (production taxes) increased $13.3 million from $20.0 million in the third quarter of 2007 to $33.4 million in the third quarter of 2008 primarily due to higher wellhead revenues. As a percentage of oil and natural gas wellhead revenues, production taxes remained relatively constant at 9.9 percent in the third quarter of 2008 as compared to 9.8 percent in the third quarter of 2007.

Impairment of long-lived assets. During the third quarter of 2008, circumstances indicated that the carrying value of the two wells we have drilled in the Tuscaloosa Marine Shale may not be recoverable. We compared the assets carrying value to the undiscounted expected future net cash flows, which indicated a need for an impairment charge. We then compared the net book value of the impaired assets to their estimated fair value, which resulted in a write-down of the value of proved oil and natural gas properties of $26.3 million. Fair value was determined using estimates of future production volumes and estimates of future prices we might receive for these volumes, discounted to a present value.

Depletion, depreciation, and amortization (DD&A) expense. DD&A expense increased $9.5 million from $49.0 million in the third quarter of 2007 to $58.5 million in the third quarter of 2008 as a result of a $1.63 increase in the per BOE rate, which contributed approximately $5.9 million of additional DD&A expense and an increase in production volumes, which increased DD&A expense by approximately $3.6 million. The increase in our average DD&A per BOE rate was attributable to higher costs incurred resulting from increases in rig rates, oilfield services costs, and acquisition costs.

Exploration expense. Exploration expense increased $4.5 million from $8.9 million in the third quarter of 2007 to $13.4 million in the third quarter of 2008. During the third quarter of 2008, we expensed 3 exploratory dry holes totaling $7.2 million. During the third quarter of 2007, we expensed 2 exploratory dry holes totaling $5.7 million. Impairment of unproved acreage through the normal course of evaluation increased $2.0 million from $3.0 million in the third quarter of 2007 to $5.0 million in the third quarter of 2008, as we continue to expand our acreage positions in certain areas and refine our estimated success rates. The following table illustrates the components of exploration expenses for the periods indicated:

	Three months ended September 30, 2008	2007	*Increase / (Decrease)*
		(in thousands)	
Dry holes	$ 7,161	$ 5,683	*$ 1,478*
Geological and seismic	1,070	153	*917*
Delay rentals	157	126	*31*
Impairment of unproved acreage	4,993	2,958	*2,035*
Total	$ 13,381	$ 8,920	*$ 4,461*

G&A expense. G&A expense increased $2.6 million from $12.7 million in the third quarter of 2007 to $15.3 million in the third quarter of 2008 primarily due to:

ENP public entity expenses;

higher activity levels;

- increased personnel costs due to intense competition for human resources within the industry; and

- an increase of (1) approximately $2.3 million for the retention bonuses paid in August 2008 and (2) approximately $1.1 million for the retention bonuses to be paid in August 2009.

Partially offsetting these increases was a $4.2 million decrease in non-cash equity-based compensation.

We expect our G&A for the fourth quarter of 2008 to include approximately $0.45 per BOE for retention bonuses to be paid in August 2009.

Table of Contents

ENCORE ACQUISITION COMPANY

Derivative fair value loss (gain). In the third quarter of 2008, we recorded a $239.4 million derivative fair value gain as compared to a derivative fair value loss of $15.8 million in the third quarter of 2007, the components of which were as follows:

	Three months ended September 30, 2008	2007	*Increase / (Decrease)*
		(in thousands)	
Mark-to-market loss (gain) on derivative contracts	$ (276,938)	$ (3,007)	*$ (273,931)*
Premium amortization	14,773	11,681	*3,092*
Settlements on commodity derivative contracts	22,730	7,112	*15,618*
Total derivative fair value loss (gain)	$ (239,435)	$ 15,786	*$ (255,221)*

During the fourth quarter of 2008, we expect to make payments for deferred premiums of commodity derivative contracts of $9.1 million. During 2009 and 2010, we expect to make payments for deferred premiums of commodity derivative contracts of $63.6 million and $5.7 million, respectively.

Interest expense. Interest expense decreased $5.8 million from $23.9 million in the third quarter of 2007 to $18.1 million in the third quarter of 2008 primarily due to (1) the use of net proceeds from our Mid-Continent asset disposition and ENP s IPO to reduce outstanding borrowings on our revolving credit facilities and (2) a reduction in LIBOR. The weighted average interest rate for all long-term debt was 5.6 percent for the third quarter of 2008 as compared to 7.1 percent for the third quarter of 2007.

The following table illustrates the components of interest expense for the periods indicated:

	Three months ended September 30, 2008	2007	*Increase / (Decrease)*
		(in thousands)	
6.25% Notes	$ 2,433	$ 2,427	*$ 6*
6.0% Notes	4,640	4,631	*9*
7.25% Notes	2,749	2,747	*2*
Revolving credit facilities	7,478	13,186	*(5,708)*
Other	824	942	*(118)*
Total	$ 18,124	$ 23,933	*$ (5,809)*

Minority interest. As of September 30, 2008, public unitholders owned approximately 33.3 percent of ENP s common units. We include ENP s results of operations in our consolidated financial statements and show the public ownership as minority interest. Minority interest in income of ENP was approximately $31.1 million for the third quarter of 2008 as compared to minority interest in loss of ENP of approximately $3.0 million for the third quarter of 2007.

Income taxes. In the third quarter of 2008, we recorded an income tax provision of $121.2 million as compared to $9.0 million in the third quarter of 2007. In the third quarter of 2008, we had income before income taxes, net of minority interest, of $327.5 million as compared to $21.0 million in the third quarter of 2007. Our effective tax rate decreased to 37.0 percent in the third quarter of 2008 as compared to 42.9 percent in the third quarter of 2007 primarily due to deferred compensation related to ENP s MIUs.

Table of Contents

ENCORE ACQUISITION COMPANY

Comparison of Nine Months Ended September 30, 2008 to Nine Months Ended September 30, 2007

Oil and natural gas revenues. The following table illustrates the components of oil and natural gas revenues for the periods indicated, as well as each period s respective production volumes and average prices:

	Nine months ended September 30,		Increase / (Decrease)	
	2008	2007	$	%
Revenues (in thousands):				
Oil wellhead	$ 778,858	$ 409,985	*$ 368,873*	
Oil commodity derivative contracts	(2,857)	(32,471)	*29,614*	
Total oil revenues	$ 776,001	$ 377,514	*$ 398,487*	*106%*
Natural gas wellhead	$ 182,973	$ 118,267	*$ 64,706*	
Natural gas commodity derivative contracts		(7,719)	*7,719*	
Total natural gas revenues	$ 182,973	$ 110,548	*$ 72,425*	*66%*
Combined wellhead	$ 961,831	$ 528,252	*$ 433,579*	
Combined commodity derivative contracts	(2,857)	(40,190)	*37,333*	
Total combined oil and natural gas revenues	$ 958,974	$ 488,062	*$ 470,912*	*96%*
Average realized prices:				
Oil wellhead ($/Bbl)	$ 104.61	$ 58.35	*$ 46.26*	
Oil commodity derivative contracts ($/Bbl)	(0.38)	(4.62)	*4.24*	
Total oil revenues ($/Bbl)	$ 104.23	$ 53.73	*$ 50.50*	*94%*
Natural gas wellhead ($/Mcf)	$ 9.67	$ 6.44	*$ 3.23*	
Natural gas commodity derivative contracts ($/Mcf)		(0.42)	*0.42*	
Total natural gas revenues ($/Mcf)	$ 9.67	$ 6.02	*$ 3.65*	*61%*
Combined wellhead ($/BOE)	$ 90.76	$ 52.37	*$ 38.39*	
Combined commodity derivative contracts ($/BOE)	(0.27)	(3.98)	*3.71*	
Total combined oil and natural gas revenues ($/BOE)	$ 90.49	$ 48.39	*$ 42.10*	*87%*

Total production volumes:				
Oil (MBbls)	7,446	7,027	*419*	*6%*
Natural gas (MMcf)	18,915	18,359	*556*	*3%*
Combined (MBOE)	10,598	10,086	*512*	*5%*
Average daily production volumes:				
Oil (Bbls/D)	27,174	25,738	*1,436*	*6%*
Natural gas (Mcf/D)	69,031	67,249	*1,782*	*3%*
Combined (BOE/D)	38,679	36,946	*1,733*	*5%*
Average NYMEX prices:				
Oil (per Bbl)	$ 113.59	$ 66.24	*$ 47.35*	*71%*
Natural gas (per Mcf)	$ 9.74	$ 6.82	*$ 2.92*	*43%*

Oil revenues increased 106 percent from $377.5 million in the first nine months of 2007 to $776.0 million in the first nine months of 2008 as a result of an increase in oil production volumes of 419 MBbls, which contributed approximately $24.5 million in additional oil revenues, and an increase in our average realized oil price. The increase in oil production volumes was the result of our Big Horn Basin asset acquisition in March 2007, our Williston Basin asset acquisition in April 2007, and our development program.

Our average realized oil price increased $50.50 per Bbl primarily as a result of an increase in our wellhead price, which increased oil revenues by approximately $344.4 million, or $46.26 per Bbl. Our average oil wellhead price increased as a result of increases in the overall market price for oil, as reflected in the increase in the average NYMEX price from $66.24 per Bbl in the first nine months of 2007 to $113.59 per Bbl in the first nine months of 2008. In addition, as a result of our discontinuance of hedge accounting in July 2006, oil revenues for the first nine months of 2007 included amortization of the effects of certain commodity derivative contracts that were previously designated as hedges of approximately $32.5 million, or $4.62 per Bbl,

39

Table of Contents

while the first nine months of 2008 only included approximately $2.9 million, or $0.38 per Bbl.

Our oil wellhead revenue was reduced by $49.7 million and $20.0 million in the first nine months of 2008 and 2007, respectively, for NPI payments related to our CCA properties.

Natural gas revenues increased 66 percent from $110.5 million for the first nine months of 2007 to $183.0 million for the first nine months of 2008 as a result of an increase in natural gas production volumes of 556 MMcf, which contributed approximately $3.6 million in additional natural gas revenues, and an increase in our average realized natural gas price. The increase in natural gas production volumes was primarily the result of our development program.

Our average realized natural gas price increased $3.65 per Mcf primarily as a result of an increase in our wellhead price, which increased natural gas revenues by approximately $61.1 million, or $3.23 per Mcf. Our average natural gas wellhead price increased as a result of increases in the overall market price for natural gas, as reflected in the increase in the average NYMEX price from $6.82 per Mcf in the first nine months of 2007 to $9.74 per Mcf in the first nine months of 2008. In addition, as a result of our discontinuance of hedge accounting in July 2006, natural gas revenues for the first nine months of 2007 included amortization of the effects of commodity certain derivative contracts that were previously designated as hedges of approximately $7.7 million, or $0.42 per Mcf.

The table below illustrates the relationship between oil and natural gas wellhead prices as a percentage of average NYMEX prices for the periods indicated. Management uses the wellhead to NYMEX margin analysis to analyze trends in our oil and natural gas revenues.

	Nine months ended September 30,	
	2008	**2007**
Oil wellhead ($/Bbl)	$ 104.61	$ 58.35
Average NYMEX ($/Bbl)	$ 113.59	$ 66.24
Differential to NYMEX	$ (8.98)	$ (7.89)
Oil wellhead to NYMEX percentage	92%	88%
Natural gas wellhead ($/Mcf)	$ 9.67	$ 6.44
Average NYMEX ($/Mcf)	$ 9.74	$ 6.82
Differential to NYMEX	$ (0.07)	$ (0.38)
Natural gas wellhead to NYMEX percentage	99%	94%

Our oil wellhead price as a percentage of the average NYMEX price improved to 92 percent for the first nine months of 2008 as compared to 88 percent for the first nine months of 2007. The differential improved because of term contracts based on a fixed differential of NYMEX and the subsequent strength of West Texas Intermediate, continued strong demand, and the relatively high price of oil sold into the Clearbrook, Minnesota market.

Our natural gas wellhead price as a percentage of the average NYMEX price improved to 99 percent for the first nine months of 2008 as compared to 94 percent for the first nine months of 2007. The differential improved because the price of NGLs increased at a faster pace than did the price of natural gas. Certain of our natural gas marketing contracts determine the price that we are paid based on the value of the dry gas sold plus a portion of the value of liquids extracted. Since title of the natural gas sold under these contracts passes at the inlet of the processing plant, we report inlet volumes of natural gas in Mcf as production.

ENCORE ACQUISITION COMPANY

Marketing revenues and expenses. The following table summarizes our marketing activities for the periods indicated:

	Nine months ended September 30, 2008	Nine months ended September 30, 2007	*Increase / (Decrease) $*	*Increase / (Decrease) %*
	($ in thousands, except per BOE amounts)			
Marketing revenues	$ 8,740	$ 27,139	*$ (18,399)*	*-68%*
Marketing expenses	9,362	27,607	*(18,245)*	*-66%*
Marketing loss	$ (622)	$ (468)	*$ (154)*	*33%*
Marketing revenues per BOE	$ 0.82	$ 2.69	*$ (1.87)*	*-70%*
Marketing expenses per BOE	0.88	2.74	*(1.86)*	*-68%*
Marketing loss per BOE	$ (0.06)	$ (0.05)	*$ (0.01)*	*20%*

In 2007, we discontinued purchasing oil from third party companies as market conditions changed and pipeline space was gained. Implementing this change allowed us to focus on the marketing of our own oil production, leveraging newly gained pipeline space, and delivering oil to various newly developed markets in an effort to maximize the value of the oil at the wellhead.

In March 2007, ENP acquired a natural gas pipeline from Anadarko as part of the Big Horn Basin asset acquisition. Natural gas volumes are purchased from numerous gas producers at the inlet to the pipeline and resold downstream to various local and off-system markets.

Marketing expenses in 2008 include pipeline tariffs, storage, truck facility fees, and tank bottom costs used to support the sale of equity crude, the revenues of which are included in our oil revenues instead of marketing revenues.

ENCORE ACQUISITION COMPANY

Expenses. The following table summarizes our expenses, excluding marketing expenses shown above, for the periods indicated:

	Nine months ended September 30,		*Increase / (Decrease)*	
	2008	**2007**	*$*	*%*
Expenses (in thousands):				
Production:				
Lease operations	$ 130,013	$ 105,186	*$ 24,827*	
Production, ad valorem, and severance taxes	95,845	51,750	*44,095*	
Total production expenses	225,858	156,936	*68,922*	*44%*
Other:				
Depletion, depreciation, and amortization	159,114	136,372	*22,742*	
Impairment of long-lived assets	26,292		*26,292*	
Exploration	30,462	23,856	*6,606*	
General and administrative	36,549	26,216	*10,333*	
Derivative fair value loss	82,093	68,166	*13,927*	
Other operating	9,805	13,667	*(3,862)*	
Total operating	570,173	425,213	*144,960*	*34%*
Interest	54,669	68,040	*(13,371)*	
Income tax provision	118,595	1,490	*117,105*	
Total expenses	$ 743,437	$ 494,743	*$ 248,694*	*50%*
Expenses (per BOE):				
Production:				
Lease operations	$ 12.27	$ 10.43	*$ 1.84*	
Production, ad valorem, and severance taxes	9.04	5.13	*3.91*	
Total production expenses	21.31	15.56	*5.75*	*37%*
Other:				
Depletion, depreciation, and amortization	15.01	13.52	*1.49*	
Impairment of long-lived assets	2.48		*2.48*	
Exploration	2.87	2.37	*0.50*	
General and administrative	3.45	2.60	*0.85*	
Derivative fair value loss	7.75	6.76	*0.99*	
Other operating	0.93	1.35	*(0.42)*	
Total operating	53.80	42.16	*11.64*	*28%*
Interest	5.16	6.75	*(1.59)*	
Income tax provision	11.19	0.15	*11.04*	
Total expenses	$ 70.15	$ 49.06	*$ 21.09*	*43%*

Production expenses. Total production expenses increased 44 percent from $156.9 million in the first nine months of 2007 to $225.9 million in the first nine months of 2008 as a result of a five percent increase in total production volumes and a $5.75 increase in the per BOE rate.

Production expense attributable to LOE increased $24.8 million from $105.2 million in the first nine months of 2007 to $130.0 million in the first nine months of 2008 as a result of an increase in production volumes, which contributed approximately $5.3 million of additional LOE, and a $1.84 increase in the per BOE rate, which contributed approximately $19.5 million of additional LOE. The increase in our LOE per BOE rate was attributable to:

- increases in prices paid to oilfield service companies and suppliers;
- increases in natural gas prices resulting in higher electricity costs and gas plant fuel costs;
- higher compensation levels for engineers and other technical professionals; and
- an increase of (1) approximately $0.44 per BOE for retention bonuses paid in August 2008 and (2) approximately $0.15 per BOE for retention bonuses to be paid in August 2009.

Production expense attributable to production taxes increased $44.1 million from $51.8 million in the first nine months of

ENCORE ACQUISITION COMPANY

2007 to $95.8 million in the first nine months of 2008 primarily due to higher wellhead revenues. As a percentage of oil and natural gas wellhead revenues, production taxes remained relatively constant at 10.0 percent in the first nine months of 2008 as compared to 9.8 percent in the first nine months of 2007.

Impairment of long-lived assets. During the third quarter of 2008, circumstances indicated that the carrying value of the two wells we have drilled in the Tuscaloosa Marine Shale may not be recoverable. We compared the assets carrying value to the undiscounted expected future net cash flows, which indicated a need for an impairment charge. We then compared the net book value of the impaired assets to their estimated fair value, which resulted in a write-down of the value of proved oil and natural gas properties of $26.3 million. Fair value was determined using estimates of future production volumes and estimates of future prices we might receive for these volumes, discounted to a present value.

DD&A expense. DD&A expense increased $22.7 million from $136.4 million in the first nine months of 2007 to $159.1 million in the first nine months of 2008 as a result of a $1.49 increase in the per BOE rate, which contributed approximately $15.8 million of additional DD&A expense, and an increase in production volumes, which contributed approximately $6.9 million of additional DD&A expense. The increase in our average DD&A per BOE rate was primarily due to:

the higher cost basis of the properties associated with our Big Horn Basin asset acquisition in March 2007;

the higher cost basis of the properties associated with our Williston Basin asset acquisition in April 2007; and

higher costs incurred resulting from increases in rig rates, oilfield services costs, and acquisition costs.

Exploration expense. Exploration expense increased $6.6 million from $23.9 million in the first nine months of 2007 to $30.5 million in the first nine months of 2008. During the first nine months of 2008, we expensed 7 exploratory dry holes totaling $14.4 million. During the first nine months of 2007, we expensed 5 exploratory dry holes totaling $14.7 million. Impairment of unproved acreage through the normal course of evaluation increased $5.5 million from $7.8 million in the first nine months of 2007 to $13.3 million in the first nine months of 2008, as we continued to expand our acreage positions in certain areas and refine our estimated success rates. The following table illustrates the components of exploration expenses for the periods indicated:

	Nine months ended September 30,		***Increase / (Decrease)***
	2008	**2007**	
	(in thousands)		
Dry holes	$ 14,395	$ 14,703	*$ (308)*
Geological and seismic	1,903	878	*1,025*
Delay rentals	860	467	*393*
Impairment of unproved acreage	13,304	7,808	*5,496*
Total	$ 30,462	$ 23,856	*$ 6,606*

G&A expense. G&A expense increased $10.3 million from $26.2 million in the first nine months of 2007 to $36.5 million in the first nine months of 2008 primarily due to:

ENP public entity expenses;

higher activity levels;

increased personnel costs due to intense competition for human resources within the industry; and an increase of (1) approximately $2.9 million for retention bonuses paid in August 2008 and (2) approximately $1.1 million for retention bonuses to be paid in August 2009.

Partially offsetting these increases was a $3.7 million decrease in non-cash equity-based compensation.

Table of Contents

ENCORE ACQUISITION COMPANY

Derivative fair value loss. In the first nine months of 2008, we recorded an $82.1 million derivative fair value loss as compared to a loss of $68.2 million in the first nine months of 2007, the components of which were as follows:

	Nine months ended September 30,		*Increase /*
	2008	**2007**	***(Decrease)***
		(in thousands)	
Mark-to-market loss (gain) on derivative contracts	$ (12,233)	$ 17,547	*$ (29,780)*
Premium amortization	47,579	29,370	*18,209*
Settlements on commodity derivative contracts	46,747	21,249	*25,498*
Total derivative fair value loss	$ 82,093	$ 68,166	*$ 13,927*

Interest expense. Interest expense decreased $13.4 million from $68.0 million in the first nine months of 2007 to $54.7 million in the first nine months of 2008 primarily due to (1) the use of net proceeds from our Mid-Continent asset disposition and ENP s IPO to reduce outstanding borrowings on our revolving credit facilities and (2) a reduction in LIBOR. The weighted average interest rate for all long-term debt was 5.8 percent for the first nine months of 2008 as compared to 7.0 percent for the first nine months of 2007.

The following table illustrates the components of interest expense for the periods indicated:

	Nine months ended September 30,		*Increase /*
	2008	**2007**	***(Decrease)***
		(in thousands)	
6.25% Notes	$ 7,294	$ 7,277	*$ 17*
6.0% Notes	13,910	13,886	*24*
7.25% Notes	8,247	8,240	*7*
Revolving credit facilities	23,082	36,208	*(13,126)*
Other	2,136	2,429	*(293)*
Total	$ 54,669	$ 68,040	*$ (13,371)*

Minority interest. Minority interest in the income of ENP was approximately $16.2 million for the first nine months of 2008 as compared to minority interest in loss of ENP $3.0 million for the first nine months of 2007.

Income taxes. In the first nine months of 2008, we recorded an income tax provision of $118.6 million as compared to $1.5 million in the first nine months of 2007. In the first nine months of 2008, we had income before income taxes, net of minority interest, of $320.4 million as compared to a loss before income taxes, net of minority interest, of $0.8 million in the first nine months of 2007. Our effective tax rate decreased to 37.0 percent for the first nine months of 2008 as compared to 45.2 percent for the first nine months of 2007 primarily due to permanent rate adjustments for a Section 199 production activities deduction and deferred compensation related to ENP s MIUs.

Capital Commitments, Capital Resources, and Liquidity

Capital commitments

Our primary needs for cash are:

Development, exploitation, and exploration of oil and natural gas properties;

Acquisitions of oil and natural gas properties;

Funding of necessary working capital; and

Contractual obligations.

Table of Contents

ENCORE ACQUISITION COMPANY

Development, exploitation, and exploration of oil and natural gas properties. The following table summarizes our costs incurred (excluding asset retirement obligations) related to development, exploitation, and exploration activities for the periods indicated:

	Three months ended September 30,		Nine months ended September 30,	
	2008	2007	2008	2007
	(in thousands)			
Development and exploitation	$ 116,376	$ 50,543	$ 250,624	$ 189,060
Exploration	69,960	27,424	179,217	77,647
Total	$ 186,336	$ 77,967	$ 429,841	$ 266,707

Our development and exploitation expenditures primarily relate to drilling development and infill wells, workovers of existing wells, and field related facilities. Our development and exploitation capital for the third quarter of 2008 yielded 58 gross (24.7 net) successful wells. Our development and exploitation capital for the first nine months of 2008 yielded 141 gross (49.8 net) successful wells and 3 gross (1.4 net) dry holes.

Our exploration expenditures primarily relate to drilling exploratory wells, seismic costs, delay rentals, and geological and geophysical costs. Our exploration capital for the third quarter of 2008 yielded 18 gross (3.6 net) successful wells and 3 gross (1.3 net) dry holes. Our exploration capital for the first nine months of 2008 yielded 69 gross (17.3 net) successful wells and 7 gross (3.8 net) dry holes.

Acquisitions of oil and natural gas properties and leasehold acreage. The following table summarizes our costs incurred (excluding asset retirement obligations) related to oil and natural gas property acquisitions for the periods indicated:

	Three months ended September 30,		Nine months ended September 30,	
	2008	2007	2008	2007
	(in thousands)			
Acquisitions of proved property	$ 8,725	$ 30,079	$ 29,193	$ 791,964
Acquisitions of leasehold acreage	61,275	16,832	95,916	40,615
Total	$ 70,000	$ 46,911	$ 125,109	$ 832,579

In March 2007, Encore Operating and OLLC acquired oil and natural gas properties in the Big Horn Basin, including properties in the Elk Basin and the Gooseberry fields for approximately $393.6 million. In April 2007, we acquired oil and natural gas properties in the Williston Basin for approximately $392.1 million.

During the three and nine months ended September 30, 2008, our capital expenditures for leasehold acreage totaled $61.3 million and $95.9 million, respectively. Of these amounts, $44.0 million related to the exercise of preferential rights in the Haynesville area and the remainder related to the acquisition of unproved acreage in various areas. During the third quarter of 2007, our capital expenditures for leasehold acreage totaled $16.8 million, all of which related to the acquisition of unproved acreage in various areas. During the first nine months of 2007, our capital expenditures for leasehold acreage totaled $40.6 million, of which $16.1 million related to the Williston Basin asset acquisition and the remainder related to the acquisition of unproved acreage in various areas.

Funding of necessary working capital. At September 30, 2008 and December 31, 2007, our working capital (defined as total current assets less total current liabilities) was negative $15.1 million and negative $16.2 million, respectively. For the remainder of 2008, we expect working capital to remain negative, primarily due to 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 reduce outstanding borrowings and related interest expense under our revolving credit facility. However, we have significant availability under our revolving credit facility to fund our obligations as they become due. We do not plan to pay cash dividends in the foreseeable future. Our production volumes, commodity prices, and differentials for oil and natural gas will be the largest variables affecting working capital in the future. Our operating cash flow is determined in large part by production volumes and commodity prices. Given our current commodity derivative contracts, assuming constant or increasing production volumes, our operating cash flow should remain positive for the remainder of 2008.

ENCORE ACQUISITION COMPANY

During the third quarter of 2008, the Board approved an increase to our total 2008 capital budget from $445 million to $613.5 million, excluding proved property acquisitions. On October 28, 2008, we announced that the Board had approved a 2009 capital budget of $460 million related to our drilling and development program. 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 significantly, depending on available opportunities, timing of projects, and market conditions. We plan to finance our ongoing expenditures using internally generated cash flow and borrowings under our revolving credit facility.

Off-balance sheet arrangements. We have no investments in unconsolidated entities or persons that could materially affect our liquidity or availability of capital resources. We have no off-balance sheet arrangements that are material to our financial position or results of operations.

Contractual obligations. The following table illustrates our contractual obligations and commitments at September 30, 2008:

Contractual Obligations and Commitments	Maturity Date	Total	Payments Due by Period: Three Months Ending December 31, 2008	Years Ending December 31, 2009 - 2010	Years Ending December 31, 2011 - 2012	Thereafter
			(in thousands)			
6.25% Senior Subordinated Notes (a)	4/15/2014	$ 206,250	$ 4,687	$ 18,750	$ 18,750	$ 164,063
6.0% Senior Subordinated Notes (a)	7/15/2015	426,000		36,000	36,000	354,000
7.25% Senior Subordinated Notes (a)	12/1/2017	253,313	5,438	21,750	21,750	204,375
Revolving credit facilities (a)	3/7/2012	707,404	6,180	49,443	651,781	
Commodity derivative contracts (b)		96,296	10,066	81,529	4,701	
Capital lease obligations		1,863	116	932	815	
Development commitments (c)		113,601	32,600	81,001		
Operating leases and commitments (d)		18,792	1,299	7,908	6,978	2,607
Asset retirement obligations (e)		172,457	191	1,534	1,534	169,198
Total		$ 1,995,976	$ 60,577	$ 298,847	$ 742,309	$ 894,243

(a) Amounts include principal and projected interest payments. Please read Note 9 of Notes to Consolidated Financial Statements included in Item 1. Financial Statements for additional information regarding our long-term debt.

(b) Represents our net liabilities for commodity derivative contracts. With the exception of $76.3 million of deferred premiums on commodity derivative contracts, the ultimate settlement amounts of our commodity derivative contracts are unknown because they are subject to continuing market risk. Please read Item 3. Quantitative and Qualitative Disclosures about Market Risk and Notes 6 and 7 of Notes to Consolidated Financial Statements included in Item 1. Financial Statements for additional information regarding our commodity derivative contracts.

(c) Development commitments include: authorized purchases for work in process of $97.7 million and future minimum payments for drilling rig operations of $15.9 million. Also at September 30, 2008, we had approximately $238.0 million of authorized purchases not placed with 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 $17.9 million and future minimum payments for other operating commitments of $0.9 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 end of field life. Please read Note 8 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 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. Alternative transportation routes and markets have been developed by moving a portion of the crude oil production through the Enbridge Pipeline to the Clearbrook, Minnesota hub. In addition, we have identified new markets to the west 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 the Platte Pipeline to Wood River, Illinois as well as other pipelines connected to the Guernsey, Wyoming area. While shipments on the Platte Pipeline are currently oversubscribed and have been subject to apportionment since December 2005, we were allocated sufficient pipeline capacity to move our equity crude oil production effective

January 1, 2007. Enbridge Pipeline North Dakota completed an expansion of

ENCORE ACQUISITION COMPANY

their pipeline in January 2008. The expansion has provided a small degree of stability to oil differentials by effectively moving the total Rockies area pipeline takeaway closer to a balancing point with increasing production volumes. In spite of the increase in capacity, the Enbridge Pipeline North Dakota continues to run at capacity and is scheduled to complete an additional expansion by the beginning of 2010. 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 slightly widen in the fourth quarter of 2008 as compared to the $10.46 per Bbl differential we realized in the third quarter of 2008. 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 affected this differential. Natural gas differentials are expected to remain approximately constant or to slightly widen in the fourth quarter of 2008 as compared to the $0.70 per Mcf differential we realized in the third quarter of 2008. We cannot accurately predict future crude oil and natural gas differentials. 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.

Capital resources

Cash flows from operating activities. Cash provided by operating activities increased $315.4 million from $213.6 million for the first nine months of 2007 to $529.0 million for the first nine months of 2008, primarily due to an increase in our production margin, partially offset by increased settlements on our commodity derivative contracts as a result of higher commodity prices.

Cash flows from investing activities. Cash used in investing activities decreased $297.1 million from $833.2 million in the first nine months of 2007 to $536.1 million in the first nine months of 2008, primarily due to a $723.2 million decrease in amounts paid for acquisitions of oil and natural gas properties, partially offset by a $290.1 million decrease in proceeds from the disposition of assets and a $125.4 million increase in development of oil and natural gas properties. In the first nine months of 2007, Encore Operating and OLLC paid approximately $393.2 million in conjunction with the Big Horn Basin asset acquisition, and we paid approximately $392.0 million in conjunction with the Williston Basin asset acquisition. In the first nine months of 2007, we also completed the sale of certain oil and natural gas properties in the Mid-Continent for net proceeds of approximately $289.7 million. During the first nine months of 2008, we advanced $33.3 million (net of collections) to ExxonMobil for their portion of costs incurred drilling wells under the joint development agreement as compared to $22.6 million in the first nine months of 2007.

Cash flows from financing activities. Our cash flows from financing activities consist primarily of proceeds from and payments on long-term debt. We periodically draw on our revolving credit facility to fund acquisitions and other capital commitments.

During the first nine months of 2008, we received net cash of $9.2 million from financing activities. During the first nine months of 2008, we had net borrowings on our revolving credit facilities of $95.7 million, which resulted in an increase in outstanding borrowings under our revolving credit facilities from $526 million at December 31, 2007 to $622.9 million at September 30, 2008. During the first nine months of 2008, ENP distributed $19.5 million to non-affiliates.

In December 2007, we announced that the Board approved a share repurchase program authorizing us to repurchase up to $50 million of our common stock. As of September 30, 2008, we had completed the share repurchase program by repurchasing and retiring 1,397,721 shares of our outstanding common stock at an average price of approximately $35.77 per share. On October 15, 2008, we announced that the Board authorized a new share repurchase program of up to $40 million of our common stock. The shares may be repurchased from time to time in the open market or through privately negotiated transactions. The repurchase program is subject to business and market conditions, and may be suspended or discontinued at any time. The share repurchase program will be funded using our available cash. As of October 29, 2008, we had repurchased and retired 620,265 shares of our outstanding common stock for approximately $17.2 million, or an average price of $27.68 per share, under the new share repurchase program.

During the first nine months of 2007, we received net cash of $627.2 million from financing activities, including net borrowings on our revolving credit facilities of $463.9 million and net proceeds of $171.2 million from ENP s issuance of 9,000,000 common units in its IPO. This cash, along with the net proceeds received from the Mid-Continent disposition, was used to finance the Big Horn Basin and Williston Basin asset acquisitions.

ENCORE ACQUISITION COMPANY

Liquidity

Our primary sources of liquidity are internally generated cash flows and the borrowing capacity under our revolving credit facility. 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 acquisitions or maintain our financial flexibility. We believe that our internally generated cash flows and availability under our revolving credit facility will be sufficient to fund our planned capital expenditures for the foreseeable future.

Internally generated cash flows. Our internally generated cash flows, results of operations, and financing for our operations are largely dependent on oil and natural gas prices. During the first nine months of 2008, our average realized oil and natural gas prices increased by 94 percent and 61 percent, respectively, as compared to the first nine months of 2007. Realized oil and natural gas prices fluctuate widely in response to changing market forces. For the first nine months of 2008, approximately 70 percent of our production was oil. As we previously discussed, our oil and natural gas wellhead differentials during the first nine months of 2008 improved as compared to the first nine months of 2007, favorably impacting the prices we received for our production. To the extent oil and natural gas prices decline or we experience a significant widening of our wellhead differentials, our earnings, cash flows from operations, and availability under our revolving credit facility may be adversely impacted. Prolonged periods of lower oil and natural gas prices or sustained wider wellhead differentials could cause us to not be in compliance with financial covenants under our revolving credit facility and thereby affect our liquidity. However, we have protected over 95 percent of our expected future production through 2009 against falling commodity prices. Please read and Note 6 of Notes to Consolidated Financial Statements included in Item 1. Financial Statements for additional information regarding our commodity derivative contracts.

Revolving credit facilities. Our principal source of short-term liquidity is our revolving credit facility. The syndicate of lenders underwriting our facility comprises 30 banking and other financial institutions, and the syndicate of lenders underwriting ENP s facility comprises 13 banking and other financial institutions, both after taking into consideration recently announced mergers and acquisitions within the financial services industry. None of the lenders are underwriting more than eight percent of the respective total commitment. We believe the large number of lenders, the relatively small percentage participation of each, and the relatively high level of availability under each facility provides adequate diversity and flexibility should further consolidation occur within the financial services industry.

<u>Encore Acquisition Company Senior Secured Credit Agreement</u>

In March 2007, we entered into a five-year amended and restated credit agreement (as amended, the EAC Credit Agreement) with a bank syndicate including Bank of America, N.A. and other lenders. Effective February 7, 2008, we amended the EAC Credit Agreement to, among other things, provide that certain negative covenants in the EAC Credit Agreement restricting hedge transactions do not apply to any oil and natural gas hedge transaction that is a floor or put transaction not requiring any future payments or delivery by us or any of our restricted subsidiaries. Effective May 22, 2008, we amended the EAC Credit Agreement to, among other things, increase the margins applicable to the ratio of total outstanding borrowings to borrowing base, as noted in the table below, and increase the borrowing base to $1.1 billion. The EAC Credit Agreement provides for revolving credit loans to be made to us from time to time and letters of credit to be issued from time to time for our account or any of our restricted subsidiaries.

The aggregate amount of the commitments of the lenders under the EAC Credit Agreement is $1.25 billion. Availability under the EAC Credit Agreement is subject to a borrowing base, which is redetermined semi-annually and upon requested special redeterminations. As of September 30, 2008, the borrowing base was $1.1 billion.

Our obligations under the EAC Credit Agreement are secured by a first-priority security interest in our restricted subsidiaries proved oil and natural gas reserves and in our equity interests in our restricted subsidiaries. In addition, our obligations under the EAC Credit Agreement are guaranteed by our restricted subsidiaries.

Loans under the EAC Credit Agreement are subject to varying rates of interest based on (1) the total amount outstanding in relation to the borrowing base and (2) 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:

Table of Contents

ENCORE ACQUISITION COMPANY

Ratio of Total Outstanding Borrowings to Borrowing Base	Applicable Margin for Eurodollar Loans	Applicable Margin for Base Rate Loans
Less than .50 to 1	1.250%	0.000%
Greater than or equal to ..50 to 1 but less than .75 to 1	1.500%	0.250%
Greater than or equal to .75 to 1 but less than .90 to 1	1.750%	0.500%
Greater than or equal to .90 to 1	2.000%	0.750%

The Eurodollar rate for any interest period (either one, two, three, or six months, as selected by us) 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 (1) the annual rate of interest announced by Bank of America, N.A. as its prime rate and (2) the federal funds effective rate plus 0.5 percent.

Any outstanding letters of credit reduce the availability under the EAC Credit Agreement. Borrowings under the EAC Credit Agreement may be repaid from time to time without penalty.

The EAC 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;
- a restriction on creating liens on our and our 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 we maintain a ratio of consolidated current assets (as defined in the EAC Credit Agreement) to consolidated current liabilities (as defined in the EAC Credit Agreement) of not less than 1.0 to 1.0; and
- a requirement that we maintain a ratio of consolidated EBITDA (as defined in the EAC 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 EAC 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 EAC Credit Agreement to be immediately due and payable.

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

Ratio of Total Outstanding Borrowings to Borrowing Base	Commitment Fee Percentage
Less than .50 to 1	0.250%
Greater than or equal to .50 to 1 but less than .75 to 1	0.300%
Greater than or equal to .75 to 1	0.375%

On September 30, 2008, there were $482.9 million of outstanding borrowings and $617.1 million of borrowing capacity under the EAC Credit Agreement. On October 28, 2008, there were $498.5 million of outstanding borrowings and $601.5 million of borrowing capacity under the EAC Credit Agreement.

Encore Energy Partners Operating LLC Credit Agreement

OLLC is a party to a five-year credit agreement dated March 7, 2007 (as amended, the OLLC Credit Agreement) with a bank syndicate including Bank of America, N.A. and other lenders. On August 22, 2007, OLLC amended its credit agreement to revise certain financial covenants. The OLLC Credit Agreement provides for revolving credit loans to be made to OLLC from time to time and letters of credit to be issued from time to time for the account of OLLC or any of its restricted subsidiaries.

ENCORE ACQUISITION COMPANY

The aggregate amount of the commitments of the lenders under the OLLC Credit Agreement is $300 million. Availability under the OLLC Credit Agreement is subject to a borrowing base, which is redetermined semi-annually and upon requested special redeterminations. As of September 30, 2008, the borrowing base was $240 million.

OLLC s obligations under the OLLC Credit Agreement are secured by a first-priority security interest in OLLC s proved oil and natural gas reserves and in OLLC s equity interests in its restricted subsidiaries. In addition, OLLC s obligations under the OLLC Credit Agreement are guaranteed by ENP and OLLC s restricted subsidiaries. We consolidate the debt of ENP with that of our own; however, obligations under the OLLC Credit Agreement are non-recourse to us and our restricted subsidiaries.

Loans under the OLLC Credit Agreement are subject to varying rates of interest based on (1) the total amount outstanding in relation to the borrowing base and (2) 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 Outstanding Borrowings to Borrowing Base	Applicable Margin for Eurodollar Loans	Applicable Margin for Base Rate Loans
Less than .50 to 1	1.000%	0.000%
Greater than or equal to .50 to 1 but less than .75 to 1	1.250%	0.000%
Greater than or equal to .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 us) 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 (1) the annual rate of interest announced by Bank of America, N.A. as its prime rate and (2) the federal funds effective rate plus 0.5 percent.

Any outstanding letters of credit reduce the availability under the OLLC Credit Agreement. Borrowings under the OLLC Credit Agreement may be repaid from time to time without penalty.

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

- a prohibition against incurring debt, subject to permitted exceptions;
- a prohibition against purchasing or redeeming capital stock, or prepaying indebtedness, subject to permitted exceptions;
- a restriction on creating liens on the assets of ENP, OLLC 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 OLLC maintain a ratio of consolidated current assets (as defined in the OLLC Credit Agreement) to consolidated current liabilities (as defined in the OLLC Credit Agreement) of not less than 1.0 to 1.0;

a requirement that OLLC maintain a ratio of consolidated EBITDA (as defined in the OLLC Credit Agreement) to the sum of consolidated net interest expense plus letter of credit fees of not less than 1.5 to 1.0;

a requirement that OLLC maintain a ratio of consolidated EBITDA (as defined in the OLLC Credit Agreement) to consolidated senior interest expense of not less than 2.5 to 1.0; and

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

The OLLC 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 OLLC Credit Agreement to be immediately due and payable.

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

Table of Contents

ENCORE ACQUISITION COMPANY

Ratio of Total Outstanding Borrowings to Borrowing Base	Commitment Fee Percentage
Less than .50 to 1	0.250%
Greater than or equal to .50 to 1 but less than .75 to 1	0.300%
Greater than or equal to .75 to 1	0.375%

On September 30, 2008, there were $140 million of outstanding borrowings, $0.1 million of outstanding letters of credit, and $99.9 million of borrowing capacity under the OLLC Credit Agreement. On October 28, 2008, there were $132 million of outstanding borrowings, $0.1 million of outstanding letters of credit, and $107.9 million of borrowing capacity under the OLLC Credit Agreement.

Please read Note 9 of Notes to Consolidated Financial Statements included in Item 1. Financial Statements for additional information regarding our long-term debt.

Debt covenants. At September 30, 2008, we and ENP were in compliance with all debt covenants.

Current capitalization. At September 30, 2008, we had total assets of $3.3 billion and total capitalization of $2.3 billion, of which 48 percent was represented by stockholders equity and 52 percent by long-term debt. At December 31, 2007, we had total assets of $2.8 billion and total capitalization of $2.1 billion, of which 46 percent was represented by stockholders equity and 54 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 or equity is used to finance capital projects or acquisitions.

Critical Accounting Policies and Estimates

Please read Item 7. Management s Discussion and Analysis of Financial Condition and Results of Operations Critical Accounting Policies and Estimates in our 2007 Annual Report on Form 10-K for additional information regarding our critical accounting policies and estimates.

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 primary objective of the following information is to provide quantitative and qualitative information about our potential exposure to market risks. The term market risk refers to the risk of loss arising from adverse changes in oil and natural gas prices and interest rates. The disclosures are not meant to be precise indicators of potential exposure, but rather indicators of potential exposure. This information provides indicators of how we view and manage our ongoing market risk exposures. All of our market risk sensitive instruments were entered into for purposes other than speculative trading.

The information included in Quantitative and Qualitative Disclosures about Market Risk in our 2007 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 commodity derivative contracts as of September 30, 2008 are discussed in Notes 6 and 7 of Notes to Consolidated Financial Statements included in Item 1. Financial Statements . The counterparties to our commodity derivative contracts are a diverse group comprising eleven institutions, all of which are currently rated A- or better by Standard & Poor s and/or Fitch, with the majority rated AA- or better. As of September 30, 2008, the fair market value of our oil and natural gas commodity derivative contracts was a net asset of approximately $38.4 million and $8.3 million, respectively. Based on our open commodity derivative positions at September 30, 2008, a $1.00 increase in the respective NYMEX prices for oil and natural gas would decrease our net derivative fair value asset by approximately $12.4 million, while a $1.00 decrease in the respective NYMEX prices for oil and natural gas would increase our net derivative fair value asset by approximately $13.8

million. These amounts exclude deferred premiums of $76.3 million that are not subject to changes in commodity prices.

Interest Rate Sensitivity

At September 30, 2008, we had total long-term debt of $1.2 billion, net of discount of $5.3 million. Of this amount, $150 million bears interest at a fixed rate of 6.25 percent, $300 million bears interest at a fixed rate of 6.0 percent, and $150 million bears interest at a fixed rate of 7.25 percent. The remaining long-term debt balance of $622.9 million consists of outstanding borrowings on 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 $6.2 million of interest expense per year on our revolving credit facilities, and if LIBOR decreased one percent, we would incur $6.2 million less. Additionally, if LIBOR increased one percent, we estimate the fair value of our fixed rate debt at September 30, 2008 would decrease from approximately $352.1 million to approximately $335.2 million, and if LIBOR decreased one percent, we estimate the fair value would increase to approximately $370.1 million.

ENP s outstanding interest rate swaps as of September 30, 2008 are discussed in Notes 6 and 7 of Notes to Consolidated Financial Statements included in Item 1. Financial Statements. As of September 30, 2008, the unrealized gain on ENP s interest rate swaps was approximately $0.2 million and is included in AOCI in our Consolidated Balance Sheet. As of September 30, 2008, the fair market value of ENP s interest rate swaps was a net asset of approximately $0.8 million. If LIBOR increased one percent, we estimate the fair value of ENP s interest rate swaps at September 30, 2008 would increase to approximately $2.4 million, and if LIBOR decreased one percent, we estimate the fair value would decrease to a net liability of approximately $0.8 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 September 30, 2008. Based on that evaluation, our Chief Executive Officer and Chief Financial Officer concluded that our disclosure controls and procedures were effective as of September 30, 2008 to ensure 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 and that information required to be disclosed is accumulated and communicated to management, including our Chief Executive Officer and Chief Financial Officer, to allow timely decisions regarding required disclosure.

There were no changes in our internal control over financial reporting during the third quarter of 2008 that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

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 our results of operations or financial position.

Item 1A. Risk Factors

Oil and natural gas prices are very volatile. A decline in commodity prices could materially and adversely affect our financial condition, results of operations, and cash flows.

The oil and natural gas markets are very volatile, and we cannot predict future oil and natural gas prices. Prices for oil and natural gas may fluctuate widely in response to relatively minor changes in the supply of and demand for oil and natural gas, market uncertainty, and a variety of additional factors that are beyond our control. Furthermore, the recent worldwide financial and credit crisis has reduced the availability of liquidity and credit to fund the continuation and expansion of industrial business operations worldwide. The shortage of liquidity and credit combined with recent substantial losses in worldwide equity markets could lead to an extended worldwide economic recession. A slowdown in economic activity caused by a recession would likely reduce worldwide demand for energy and result in lower oil and natural gas prices. Oil prices declined from record levels in early July 2008 of over $140 per Bbl to below $70 per Bbl in late October 2008, while natural gas prices have declined from over $13 per Mcf to below $7 per Mcf over the same period. In addition, the forecasted prices for the remainder of 2008 and for 2009 have also declined. Our revenue, profitability, and cash flow depend upon the prices of and demand for oil and natural gas, and a drop in prices can significantly affect our financial results and impede our growth. In particular, declines in commodity prices will:

- negatively impact the value of our reserves, because declines in oil and natural gas prices would reduce the amount of oil and natural gas that we can produce economically;

- reduce the amount of cash flow available for capital expenditures, repayment of indebtedness and other corporate purposes; and

- result in a decrease in the borrowing base under our revolving credit facility or otherwise limit our ability to borrow money or raise additional capital.

The counterparties to our commodity derivative contracts may not be able to perform their obligations to us, which could materially affect our cash flows and results of operations.

To reduce our exposure to adverse fluctuations in the prices of oil and natural gas, we currently, and may in the future, enter into commodity derivative contracts for a significant portion of our forecasted oil and natural gas production. The extent of our commodity price exposure is related largely to the effectiveness and scope of our derivative activities, as well as to the ability of counterparties under our commodity derivative contracts to satisfy their obligations to us. As of October 20, 2008, we were entitled to future payments of approximately $238.3 million from counterparties under our commodity derivative contracts. The recent worldwide financial and credit crisis may have adversely affected the ability of these counterparties to fulfill their obligations to us. If one or more of our counterparties is unable or unwilling to make required payments to us under our commodity derivative contracts, it could have a material adverse effect on our financial condition and results of operations.

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 2007 Annual Report on Form 10-K, which could materially affect our business, financial condition, and/or future results. The risks described in our 2007 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 may also materially adversely affect our business, financial condition, or results of operations.

Table of Contents

ENCORE ACQUISITION COMPANY

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

Issuer Purchases of Equity Securities

In December 2007, we announced that the Board approved a share repurchase program authorizing us to repurchase up to $50 million of our common stock. As of September 30, 2008, we had completed the share repurchase program. The following table summarizes purchases of our common stock during the third quarter of 2008:

Month	Total Number of Shares Purchased	Average Price Paid per Share	Total Number of Shares Purchased as Part of Publicly Announced Plans or Programs	Approximate Dollar Value of Shares That May Yet Be Purchased Under the Plans or Programs
July		$		
August	202,032	$ 48.75	202,032	
September	20,998	$ 49.15	20,998	
Total	223,030	$ 48.79	223,030	$

Item 6. Exhibits

Exhibits

3.1 Second Amended and Restated Certificate of Incorporation of Encore Acquisition Company (incorporated by reference from Exhibit 3.1 to EAC s Quarterly Report on Form 10-Q for the 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 Encore Acquisition Company (incorporated by reference from Exhibit 3.1.2 to EAC s Quarterly Report on Form 10-Q for the quarter ended March 31, 2005, filed with the SEC on May 5, 2005).

3.1.3 Certificate of Designations of Series A Junior Participating Preferred Stock of Encore Acquisition Company (incorporated by reference from Exhibit 3.1 to EAC s Current Report on Form 8-K, filed with the SEC on October 31, 2008).

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

4.1 Rights Agreement dated as of October 28, 2008 between Encore Acquisition Company and BNY Mellon Shareowner Services, LLC, as Rights Agent (incorporated by reference from Exhibit 4.1 to EAC s Current Report on Form 8-K, filed with the SEC on October 31, 2008).

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.

Table of Contents

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: October 31, 2008

/s/ Andrea Hunter
Andrea Hunter
Vice President, Controller,
and Principal Accounting Officer

54