ENCORE ACQUISITION CO
Form 10-Q
August 05, 2009

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

(Mark One)

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

For the quarterly period ended June 30, 2009

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 has submitted electronically and posted on its corporate Web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files). Yes o 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.

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 July 31, 2009	52,793,909

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CAUTIONARY STATEMENT REGARDING FORWARD-LOOKING INFORMATION

Certain information included in this Quarterly Report on Form 10-Q (the Report) and our other materials filed with the United States Securities and Exchange Commission (SEC), or in other written or oral statements made or to be made by us, other than statements of historical fact, are forward-looking statements as defined by the safe harbor provisions of the Private Securities Litigation Reform Act of 1995. These forward-looking statements give our current expectations or forecasts of future events. 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. You 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 and elsewhere in our 2008 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.

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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 summarized 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 hydrocarbons.

Council of Petroleum Accountants Societies (COPAS). A professional organization of petroleum 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 or Unsuccessful Well. 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.

EAC. Encore Acquisition Company, a publicly traded 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 hydrocarbons in an unproved area, to find a new reservoir in a field previously producing hydrocarbons in another reservoir, or to extend a known reservoir.

FASB. Financial Accounting Standards Board.

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.

GAAP. Accounting principles generally accepted in the United States.

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

Lease Operating Expense (LOE). All direct and allocated indirect costs of producing hydrocarbons after the completion of drilling and before the commencement of production. 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 Production. Production owned by an entity less royalties, net profits interests, and production due others.

Net Profits Interest. An interest that entitles the owner to a specified share of net profits from the 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 a well or lease.

Production Margin. Wellhead revenues less production costs.

Productive Well or Successful Well. A well capable of producing hydrocarbons in commercial quantities, including natural gas wells awaiting pipeline connections to commence deliveries and oil wells awaiting connection to production facilities.

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

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ENCORE ACQUISITION COMPANY

Proved Reserves. The estimated quantities of hydrocarbons that geological and engineering data demonstrate with reasonable certainty are recoverable in future periods from known reservoirs under existing economic and operating conditions.

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. Includes 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 from an existing wellbore 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 hydrocarbons that is confined by impermeable rock or water barriers and is individual and separate from other reservoirs.

Royalty. An interest in an oil and natural gas lease that gives the owner the right to receive a portion of the production from the leased acreage (or of the proceeds from the sale thereof), but does not require the owner to pay any portion of the production or development costs on the leased acreage. Royalties may be either landowner s royalties, which are reserved by the owner of the leased acreage at the time the lease is granted, or overriding royalties, which are usually reserved by an owner of the leasehold in connection with a transfer to a subsequent owner.

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. Involves maintaining or enhancing reservoir pressure by injecting water, gas, or other substances into the formation in order to displace hydrocarbons toward the wellbore. The most common secondary recovery techniques are gas injection and waterflooding.

SFAS. Statement of Financial Accounting Standards.

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 hydrocarbons 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.

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PART I. FINANCIAL INFORMATION

Item 1. Financial Statements

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

	June 30, 2009 (unaudited)	December 31, 2008
ASSETS		
Current assets:		
Cash and cash equivalents	$ 35,840	$ 2,039
Accounts receivable, net of allowance for doubtful accounts of $434 and $381, respectively	96,591	117,995
Current portion of long-term receivables	13,260	11,070
Inventory	27,266	24,798
Derivatives	53,204	349,344
Income taxes receivable	5,452	29,445
Other	5,286	6,239
Total current assets	236,899	540,930
Properties and equipment, at cost successful efforts method:		
Proved properties, including wells and related equipment	3,743,817	3,538,459
Unproved properties	114,168	124,339
Accumulated depletion, depreciation, and amortization	(914,021)	(771,564)
	2,943,964	2,891,234
Other property and equipment	25,794	25,192
Accumulated depreciation	(14,854)	(12,753)
	10,940	12,439
Acquisition deposit	37,500	
Goodwill	60,606	60,606
Derivatives	48,151	38,497
Long-term receivables, net of allowance for doubtful accounts of $11,981 and $7,643, respectively	51,419	60,915
Other	31,490	28,574
Total assets	$ 3,420,969	$ 3,633,195
LIABILITIES AND EQUITY		
Current liabilities:		
Accounts payable	$ 15,808	$ 10,017
Accrued liabilities:		

Lease operating expense	24,796	19,108
Development capital	56,144	79,435
Interest	16,059	11,808
Production, ad valorem, and severance taxes	28,392	25,133
Compensation	19,865	16,216
Derivatives	23,214	63,476
Oil and natural gas revenues payable	11,373	10,821
Deferred taxes	76,862	105,768
Other	17,411	10,470
Total current liabilities	289,924	352,252
Derivatives	47,861	8,922
Future abandonment cost, net of current portion	47,985	48,058
Deferred taxes	408,514	416,915
Long-term debt	1,172,912	1,319,811
Other	3,647	3,989
Total liabilities	1,970,843	2,149,947
Commitments and contingencies (see Note 14)		
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, 51,870,080 and 51,551,937 issued and outstanding, respectively	519	516
Additional paid-in capital	542,278	525,763
Treasury stock, at cost, 466 and 4,753 shares, respectively	(16)	(101)
Retained earnings	733,309	789,698
Accumulated other comprehensive loss	(1,434)	(1,748)
Total EAC stockholders equity	1,274,656	1,314,128
Noncontrolling interest	175,470	169,120
Total equity	1,450,126	1,483,248
Total liabilities and equity	$ 3,420,969	$ 3,633,195

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

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

	Three months ended June 30, 2009	Three months ended June 30, 2008	Six months ended June 30, 2009	Six months ended June 30, 2008
Revenues:				
Oil	$ 133,677	$ 286,924	$ 221,966	$ 507,458
Natural gas	29,486	67,889	54,740	116,201
Marketing	315	2,521	1,121	6,577
Total revenues	163,478	357,334	277,827	630,236
Expenses:				
Production:				
Lease operating	40,451	40,697	84,676	81,047
Production, ad valorem, and severance taxes	17,033	35,043	28,852	62,495
Depletion, depreciation, and amortization	74,434	51,026	144,734	100,569
Exploration	15,934	11,593	27,133	17,081
General and administrative	13,779	11,559	27,473	21,246
Marketing	515	3,725	1,254	7,507
Derivative fair value loss	61,106	256,390	12,515	321,528
Other operating	14,835	3,226	21,178	5,732
Total expenses	238,087	413,259	347,815	617,205
Operating income (loss)	(74,609)	(55,925)	(69,988)	13,031
Other income (expenses):				
Interest	(19,126)	(16,785)	(35,089)	(36,545)
Other	657	686	1,211	1,537
Total other expenses	(18,469)	(16,099)	(33,878)	(35,008)
Loss before income taxes	(93,078)	(72,024)	(103,866)	(21,977)
Income tax benefit	31,558	21,322	36,443	2,589
Consolidated net loss	(61,520)	(50,702)	(67,423)	(19,388)
Less: net loss attributable to noncontrolling interest	14,545	14,982	12,892	14,888
Net loss attributable to EAC	$ (46,975)	$ (35,720)	$ (54,531)	$ (4,500)

Net loss per common share:								
Basic	$	(0.91)	$	(0.68)	$	(1.05)	$	(0.09)
Diluted	$	(0.91)	$	(0.68)	$	(1.05)	$	(0.09)
Weighted average common shares outstanding:								
Basic		51,849		52,344		51,769		52,571
Diluted		51,849		52,344		51,769		52,571

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

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ENCORE ACQUISITION COMPANY
CONSOLIDATED STATEMENT OF EQUITY AND COMPREHENSIVE LOSS
(in thousands)
(unaudited)

	EAC Stockholders								
	Issued Shares of Common Stock	Common Stock	Additional Paid-in Capital	Shares of Treasury Stock	Treasury Stock	Retained Earnings	Accumulated Other Comprehensive Loss	Noncontrolling Interest	Total Equity
Balance at December 31, 2008	51,557	$ 516	$ 525,763	(5)	$ (101)	$ 789,698	$ (1,748)	$ 169,120	$ 1,483,248
Exercise of stock options and vesting of restricted stock	429	3	415						418
Purchase of treasury stock				(111)	(2,961)				(2,961)
Cancellation of treasury stock	(116)		(1,188)	116	3,046	(1,858)			
Non-cash equity-based compensation			7,859					69	7,928
ENP cash distributions to noncontrolling interest								(12,153)	(12,153)
ENP issuance of common units								40,520	40,520
Adjustment to reflect gain on ENP issuance of common units			9,312					(9,312)	
Other			117						117
Components of comprehensive loss:									
Consolidated net loss						(54,531)		(12,892)	(67,423)
Change in deferred hedge loss on interest rate swaps, net of tax of $219							314	118	432
									(66,991)

Total comprehensive loss								
Balance at June 30, 2009	51,870	$ 519	$ 542,278	$ (16)	$ 733,309	$ (1,434)	$ 175,470	$ 1,450,126

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

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

	Six months ended June 30, 2009	Six months ended June 30, 2008
Cash flows from operating activities:		
Consolidated net loss	$ (67,423)	$ (19,388)
Adjustments to reconcile net loss to net cash provided by operating activities:		
Depletion, depreciation, and amortization	144,734	100,569
Non-cash exploration expense	26,264	15,545
Deferred taxes	(37,514)	(26,756)
Non-cash equity-based compensation expense	6,863	6,205
Non-cash derivative loss	98,325	300,370
Gain on disposition of assets	(43)	(79)
Other	14,039	6,619
Changes in operating assets and liabilities:		
Accounts receivable	39,030	(47,301)
Current derivatives	257,137	(670)
Other current assets	16,142	(9,680)
Long-term derivatives		(1,196)
Other assets	5,835	(1,033)
Accounts payable	10,719	4,208
Other current liabilities	30,702	25,825
Other noncurrent liabilities	(663)	(923)
Net cash provided by operating activities	544,147	352,315
Cash flows from investing activities:		
Proceeds from disposition of assets	514	631
Purchases of other property and equipment	(772)	(1,622)
Acquisition of oil and natural gas properties	(39,990)	(49,280)
Divestiture of oil and natural gas properties	(220)	
Deposit on acquisition of oil and natural gas properties	(37,500)	
Development of oil and natural gas properties	(235,101)	(233,225)
Net collections from (advances to) working interest partners	3,709	(22,907)
Net cash used in investing activities	(309,360)	(306,403)
Cash flows from financing activities:		
Repurchase and retirement of common stock		(39,118)
Exercise of stock options and vesting of restricted stock, net of treasury stock purchases	(2,543)	374

Proceeds from long-term debt, net of issuance costs	320,450	618,339
Payments on long-term debt	(473,000)	(598,500)
ENP cash distributions to noncontrolling interest	(12,153)	(11,168)
Proceeds from ENP issuance of common units, net of offering costs	40,724	
Payments of deferred commodity derivative contract premiums	(69,536)	(20,583)
Change in cash overdrafts	(4,928)	4,634
Net cash used in financing activities	(200,986)	(46,022)
Increase (decrease) in cash and cash equivalents	33,801	(110)
Cash and cash equivalents, beginning of period	2,039	1,704
Cash and cash equivalents, end of period	$ 35,840	$ 1,594

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

ENCORE ACQUISITION COMPANY
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS
(unaudited)

Note 1. Description of Business

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, and reengineering or expanding existing waterflood projects. EAC s properties and oil and natural gas reserves are located in four core areas:

- the Cedar Creek Anticline (CCA) in the Williston Basin in Montana and North Dakota;
- the Permian Basin in West Texas and southeastern New Mexico;
- the Rockies, which includes non-CCA assets in the Williston, Big Horn, and Powder River Basins in Wyoming, Montana, and North Dakota, and the Paradox Basin in southeastern Utah; and
- the Mid-Continent area, which includes the Arkoma and Anadarko Basins in Arkansas and 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 its 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 June 30, 2009, results of operations for the three and six months ended June 30, 2009 and 2008, and cash flows for the six months ended June 30, 2009 and 2008. 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 notes thereto included in EAC s 2008 Annual Report on Form 10-K.

Noncontrolling Interest

As of June 30, 2009 and December 31, 2008, EAC owned approximately 58 percent and 63 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 indirect wholly owned non-guarantor subsidiary of EAC. GP LLC is ENP s general partner. Considering the presumption of control of GP LLC in accordance with Emerging Issues Task Force (EITF) 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.

As presented in the accompanying Consolidated Balance Sheets, Noncontrolling interest as of June 30, 2009 and December 31, 2008 of $175.5 million and $169.1 million, respectively, represents third-party ownership interests in ENP. As presented in the accompanying Consolidated Statements of Operations, Net loss attributable to noncontrolling interest for the three and six months ended June 30, 2009 of $14.5 million and $12.9 million, respectively, and for the three and six months ended June 30, 2008 of $15.0 million and $14.9 million, respectively, represents the net loss of ENP attributable to third-party owners.

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

The following table summarizes the effects of changes in EAC s ownership interest in ENP on EAC s equity for the periods indicated:

	Three months ended June 30,		Six months ended June 30,	
	2009	2008	2009	2008
	(in thousands)			
Net loss attributable to EAC	$ (46,975)	$ (35,720)	$ (54,531)	$ (4,500)
Transfer from (to) noncontrolling interest:				
Increase in EAC s paid-in capital for ENP s issuance of 283,700 common units in connection with acquisition of net profits interest in certain Crockett County properties		3,458		3,458
Increase in EAC s paid-in capital for ENP s issuance of 2,760,000 common units in public offering	9,312		9,312	
Net transfer from (to) noncontrolling interest	9,312	3,458	9,312	3,458
Change from net loss attributable to EAC and transfers from (to) noncontrolling interest	$ (37,663)	$ (32,262)	$ (45,219)	$ (1,042)

Supplemental Disclosures of Cash Flow Information

The following table sets forth supplemental disclosures of cash flow information for the periods indicated:

	Six months ended June 30,	
	2009	2008
	(in thousands)	
Non-cash investing and financing activities:		
Deferred premiums on commodity derivative contracts	$40,087	$25,685
ENP s issuance of common units in connection with acquisition of net profits interest in certain Crockett County properties		5,748

Allowance for Doubtful Accounts

During the three months ended June 30, 2009, EAC recorded bad debt expense of approximately $4.7 million, primarily related to balances due from ExxonMobil Corporation (ExxonMobil) in connection with EAC s joint development agreement, which is included in Other operating expense in the accompanying Consolidated Statements of Operations. The following table summarizes the changes in allowance for doubtful accounts for the six months ended June 30, 2009 (in thousands):

Allowance for doubtful accounts at January 1, 2009	$ 8,024
Bad debt expense	4,678
Write off	(287)
Allowance for doubtful accounts at June 30, 2009	$ 12,415

Of the $12.4 million allowance for doubtful accounts at June 30, 2009, $0.4 million is short-term and $12.0 million is long-term.

Reclassifications

Certain amounts in prior periods have been reclassified to conform to the current period presentation. In particular, certain amounts in the Consolidated Financial Statements have been either combined or classified in more detail.

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

New Accounting Pronouncements

FASB Staff Position (FSP) No. FAS 157-2, Effective Date of FASB Statement No. 157 (FSP FAS 157-2)

In February 2008, the FASB issued FSP FAS 157-2, which delayed the effective date of SFAS No. 157, Fair Value Measurements (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. FSP FAS 157-2 was prospectively effective for financial statements issued for fiscal years beginning after November 15, 2008, and interim periods within those fiscal years. The adoption of FSP FAS 157-2 on January 1, 2009 did not have a material impact on EAC s results of operations or financial condition. Please read Note 5. Fair Value Measurements for additional discussion.

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. In April 2009, the FASB issued FSP No. FAS 141(R)-1, *Accounting for Assets Acquired and Liabilities Assumed in a Business Combination That Arises from Contingencies* (FSP FAS 141R-1), which amends and clarifies SFAS 141R to address application issues, including: (1) initial recognition and measurement; (2) subsequent measurement and accounting; and (3) disclosure of assets and liabilities arising from contingencies in a business combination. SFAS 141R and FSP FAS 141R-1 were prospectively effective for business combinations consummated in fiscal years beginning on or after December 15, 2008. The adoption of SFAS 141R and FSP FAS 141R-1 on January 1, 2009 did not have a material impact on EAC s results of operations or financial condition. However, the application of SFAS 141R and FSP FAS 141R-1 to future acquisitions could impact EAC s results of operations and financial condition and the reporting of acquisitions in the 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 was prospectively effective for fiscal years beginning on or after December 15, 2008, except for the presentation and disclosure requirements which were retrospectively effective. SFAS 160 clarifies that a noncontrolling interest in a subsidiary, which was often 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 for the amounts attributable to both the parent and the noncontrolling interest on the face of the consolidated statement of operations and gains on a subsidiaries issuance of equity to be accounted for as capital transactions. The adoption of SFAS 160 on January 1, 2009 did not have a material impact on EAC s 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), to require enhanced disclosures, including: (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 was prospectively effective for financial statements issued for fiscal years beginning on or after November 15, 2008, and interim periods within those fiscal years. The adoption of SFAS 161 on January 1, 2009 required additional disclosures regarding EAC s derivative instruments; however, it did not impact EAC s results of operations or financial condition. Please read Note 5. Fair Value Measurements for additional discussion.

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

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 prescribed by SFAS No. 128, *Earnings per Share* (SFAS 128). FSP EITF 03-6-1 was retroactively effective for financial statements issued for fiscal years beginning after December 15, 2008, and interim periods within those fiscal years. The adoption of FSP EITF 03-6-1 on January 1, 2009 did not have a material impact on EAC s results of operations or financial condition. All periods presented in the accompanying Consolidated Financial Statements have been restated to reflect the adoption of FSP EITF 03-6-1. Please read Note 10. Earnings Per Share for additional discussion.

SEC Release No. 33-8995, Modernization of Oil and Gas Reporting (Release 33-8995)

In December 2008, the SEC issued Release 33-8995, which amends oil and natural gas reporting requirements under Regulations S-K and S-X. Release 33-8995 also adds a section to Regulation S-K (Subpart 1200) to codify the revised disclosure requirements in Securities Act Industry Guide 2, which is being phased out. Release 33-8995 permits the use of new technologies to determine proved reserves if those technologies have been demonstrated empirically to lead to reliable conclusions about reserves volumes. Release 33-8995 will also allow companies to disclose their probable and possible reserves to investors at the company s option. In addition, the new disclosure requirements require companies to: (1) report the independence and qualifications of its reserves preparer or auditor; (2) file reports when a third party is relied upon to prepare reserves estimates or conduct a reserves audit; and (3) report oil and gas reserves using an average price based upon the prior 12-month period rather than a year-end price, unless prices are defined by contractual arrangements, excluding escalations based on future conditions. Release 33-8995 is prospectively effective for financial statements issued for fiscal years ending on or after December 31, 2009. EAC is evaluating the impact Release 33-8995 will have on its financial condition, results of operations, and disclosures.

FSP No. FAS 107-1 and APB 28-1, Disclosure of Fair Value of Financial Instruments in Interim Statements (FSP FAS 107-1 and APB 28-1)

In April 2009, the FASB issued FSP FAS 107-1 and APB 28-1, which requires that disclosures concerning the fair value of financial instruments be presented in interim as well as annual financial statements. FSP FAS 107-1 and APB 28-1 is prospectively effective for financial statements issued for interim periods ending after June 15, 2009. The adoption of FSP FAS 107-1 and APB 28-1 required additional disclosures regarding EAC s financial instruments; however, it did not impact EAC s results of operations or financial condition. Please read Note 5. Fair Value Measurements for additional discussion.

SFAS No. 165, Subsequent Events (SFAS 165)

In June 2009, the FASB issued SFAS 165 to establish general standards of accounting for and disclosure of events that occur after the balance sheet date but before financial statements are issued or available to be issued. In particular, SFAS 165 sets forth: (1) the period after the balance sheet date during which management of a reporting entity should evaluate events or transactions that may occur for potential recognition or disclosure in the financial statements; (2) the circumstances under which an entity should recognize events or transactions occurring after the balance sheet date in its financial statements; and (3) the disclosures that an entity should make about events or transactions that occurred after the balance sheet date. SFAS 165 is prospectively effective for financial statements issued for interim or annual periods ending after June 15, 2009. The adoption of SFAS 165 on June 30, 2009 did not impact EAC s results of operations or financial condition.

SFAS No. 168, The FASB Accounting Standards Codification and the Hierarchy of Generally Accepted Accounting Principles (SFAS 168)

In June 2009, the FASB issued SFAS 168, which replaces SFAS No. 162, *The Hierarchy of Generally Accepted Accounting Principles.* SFAS 168 establishes the FASB Accounting Standards Codification as the sole source of authoritative accounting principles recognized by the FASB to be applied by all nongovernmental entities in the preparation of financial statements in conformity with GAAP. SFAS 168 is prospectively effective for financial statements for fiscal years ending on or after September 15, 2009, and interim periods within those fiscal years. The adoption of SFAS 168 on July 1, 2009 did not impact EAC s results of operations or financial condition.

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Note 3. Inventory

Inventory includes 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:

	June 30, 2009	December 31, 2008
	(in thousands)	
Materials and supplies	$ 19,766	$ 15,933
Oil in pipelines	7,500	8,865
Total inventory	$ 27,266	$ 24,798

During the three months ended June 30, 2009, EAC recorded a lower of cost or market adjustment of approximately $5.7 million to the carrying value of pipe and other tubular inventory whose market value had declined below cost, which is included in Other operating expense in the accompanying Consolidated Statements of Operations.

Note 4. 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:

	June 30, 2009	December 31, 2008
	(in thousands)	
Proved leasehold costs	$ 1,448,959	$ 1,421,859
Wells and related equipment Completed	2,252,196	1,943,275
Wells and related equipment In process	42,662	173,325
Total proved properties	$ 3,743,817	$ 3,538,459

Note 5. Fair Value Measurements

The following table sets forth EAC s book value and estimated fair value of financial instruments as of the dates indicated:

	June 30, 2009		December 31, 2008	
	Book Value	Fair Value	Book Value	Fair Value
	(in thousands)			
Assets:				
Cash and cash equivalents	$ 35,840	$ 35,840	$ 2,039	$ 2,039
Accounts receivable, net	96,591	96,591	117,995	117,995
Plugging bond	849	1,003	824	1,202
Bell Creek escrow	9,257	9,258	9,229	9,241
Commodity derivative contracts	101,355	101,355	387,841	387,841

Long-term receivables, net	64,679	64,679	71,986	71,986
Liabilities:				
Accounts payable	15,808	15,808	10,017	10,017
6.25% Senior Subordinated Notes	150,000	126,000	150,000	101,250
6.0% Senior Subordinated Notes	296,292	249,000	296,040	194,250
9.5% Senior Subordinated Notes	207,799	222,188		
7.25% Senior Subordinated Notes	148,821	127,500	148,771	94,500
Revolving credit facilities	370,000	370,000	725,000	725,000
Commodity derivative contracts	28,323	28,323	229	229
Deferred premiums on commodity derivative contracts	38,927	38,927	67,610	67,610
Interest rate swaps	3,825	3,825	4,559	4,559

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The book values of cash and cash equivalents, accounts receivable, net, and accounts payable approximate fair value due to the short-term nature of these instruments. The book value of long-term receivables, net, approximates fair value as it is net of amounts deemed to be uncollectible and bears interest at market rates. The plugging bond and Bell Creek escrow are included in Other assets on the accompanying Consolidated Balance Sheets and are classified as held to maturity and therefore, are recorded at amortized cost, which was less than fair value. The fair values of the plugging bond and Bell Creek escrow were determined using open market quotes. The fair values of the senior subordinated notes were determined using open market quotes. The difference between book value and fair value represents the premium or discount on that date. The book value of the revolving credit facilities approximates fair value as the interest rate is variable. Commodity derivative contracts and interest rate swaps are marked-to-market each quarter. Deferred premiums on commodity derivative contracts were recorded at their net present value at the time the contracts were entered into and EAC accretes that value to the eventual settlement price by recording interest expense each period.

Derivative Policy

EAC uses various financial instruments for non-trading purposes to manage and reduce price volatility and other market risks associated with its oil and natural gas production. These arrangements are structured to reduce EAC s exposure to commodity price decreases, but they can also limit the benefit EAC might otherwise receive from commodity price increases. EAC s risk management activity is generally accomplished through over-the-counter derivative contracts with large financial institutions. EAC also uses derivative instruments in the form of interest rate swaps, which hedge risk related to interest rate fluctuation.

EAC applies the provisions of SFAS 133, which requires each derivative instrument to be recorded in the balance sheet at fair value. If a derivative has not been designated as a hedge or does not otherwise qualify for hedge accounting, it must be adjusted to fair value through earnings. However, if a derivative qualifies for hedge accounting, depending on the nature of the hedge, changes in fair value can be recognized in accumulated other comprehensive loss until such time as the hedged item is recognized in earnings.

In order to qualify for cash flow hedge accounting, the cash flows from the hedging instrument must be highly effective in offsetting changes in cash flows of the hedged item. In addition, all hedging relationships must be designated, documented, and reassessed periodically. The effective portion of cash flow hedges are marked to market through accumulated other comprehensive loss each period.

EAC has elected to designate its current interest rate swaps as cash flow hedges. The effective portion of the mark-to-market gain or loss on these derivative instruments is recorded in Accumulated other comprehensive loss on the accompanying Consolidated Balance Sheets and reclassified into earnings in the same period in which the hedged transaction affects earnings. Any ineffective portion of the mark-to-market gain or loss is recognized in earnings as Derivative fair value loss in the accompanying Consolidated Statements of Operations.

EAC has not elected to designate its current portfolio of commodity derivative contracts as hedges. Therefore, changes in fair value of these derivative instruments are recognized in earnings as Derivative fair value loss in the accompanying Consolidated Statements of Operations.

Commodity Derivative Contracts

EAC manages commodity price risk with swap contracts, put contracts, collars, and floor spreads. Swap contracts provide a fixed price for a notional amount of sales volumes. Put contracts provide a fixed floor price on a notional amount of sales volumes while allowing full price participation if the relevant index price closes above the floor price. Collars provide a floor price on a notional amount of sales volumes while allowing some additional price participation if the relevant index price closes above the floor price.

From time to time, EAC enters into floor spreads. In a floor spread, EAC purchases puts at a specified price (a purchased put) and also sells a put at a lower price (a short put). This strategy enables EAC to achieve downside protection for a portion of its production, while funding the cost of such protection by selling a put at a lower price. If the price of the commodity falls below the strike price of the purchased put, then EAC has protection against commodity price decreases for the covered production down to the strike price of the short put. At commodity prices below the strike price of the short put, the benefit from the purchased put is generally offset by the expense associated with the short put. For example, in 2007, EAC purchased oil put options for 2,000 Bbls/D in 2010 at $65 per Bbl. As NYMEX prices increased in 2008, EAC wished to protect downside price exposure at the higher price. In order to do this, EAC purchased oil put options for 2,000 Bbls/D in 2010 at $75 per Bbl and simultaneously sold oil put options for

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2,000 Bbls/D in 2010 at $65 per Bbl. Thus, after these transactions were completed, EAC had purchased two oil put options for 2,000 Bbls/D in 2010 (one at $65 per Bbl and one at $75 per Bbl) and sold one oil put option for 2,000 Bbls/D in 2010 at $65 per Bbl. However, the net effect resulted in EAC owning one oil put option for 2,000 Bbls/D at $75 per Bbl. In the following tables, the purchased floor component of these floor spreads are shown net and included with EAC s other floor contracts.

The following tables summarize EAC s open commodity derivative contracts as of June 30, 2009:

Oil Derivative Contracts

Period	Average Daily Floor Volume (Bbls)	Weighted Average 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)
July Dec. 2009 (a)							$ 21,227
	3,130	$ 110.00	440	$ 97.75		$	
					1,000	68.70	
2010							(172)
	880	80.00	440	93.80			
	2,000	75.00	3,000	74.13	1,385	75.78	
	8,385	62.83	500	65.60	1,750	64.08	
	1,000	56.00			1,000	59.70	
2011							23,343
	1,880	80.00	1,440	95.41	325	80.00	
	2,500	70.00			1,060	78.42	
	4,385	65.00			250	69.65	
2012							2,918
	750	70.00	500	82.05	835	81.19	
	2,135	65.00	250	79.25	1,300	76.54	
							$ 47,316

(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

	Average	Weighted	Average	Weighted	Average	Weighted	Asset

Period	Daily Floor Volume (Mcf)	Average Floor Price (per Mcf)	Daily Cap Volume (Mcf)	Average Cap Price (per Mcf)	Daily Swap Volume (Mcf)	Average Swap Price (per Mcf)	(Liability) Fair Market Value (in thousands)
July Dec. 2009							$ 12,715
	3,800	$ 8.20	3,800	$ 9.83		$	
	3,800	7.20	5,000	7.45			
	6,800	6.57	15,000	6.63			
	15,000	5.64					
2010							14,169
	3,800	8.20	3,800	9.58	25,452	6.46	
	4,698	7.26			550	5.86	
2011							993
	3,398	6.31			27,952	6.48	
					550	5.86	
2012							(2,161)
	898	6.76			25,452	6.47	
					550	5.86	
							$ 25,716

As of June 30, 2009, EAC had $38.9 million of deferred premiums payable, of which $29.0 million was long-term and included in Derivatives in the non-current liabilities section of the accompanying Consolidated Balance Sheet and $9.9 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 July 2009 to January 2013.

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Counterparty Risk. At June 30, 2009, EAC had committed greater than 10 percent (in terms of fair market value) of either its oil or natural gas derivative contracts to the following counterparties:

Counterparty	Percentage of Oil Derivative Contracts Committed	Percentage of Natural Gas Derivative Contracts Committed
BNP Paribas	42%	24%
Calyon	19%	39%
JP Morgan	11%	14%
Wachovia Bank	12%	22%

In order to mitigate the credit risk of financial instruments, EAC enters into master netting agreements with significant counterparties. The master netting agreement is a standardized, bilateral contract between a given counterparty and EAC. Instead of treating each derivative financial transaction between the counterparty and EAC separately, the master netting agreement enables the counterparty and EAC to aggregate all financial trades and treat them as a single agreement. This arrangement benefits EAC in three ways: (1) the netting of the value of all trades reduces the likelihood of counterparties requiring daily collateral posting by EAC; (2) default by a counterparty under one financial trade can trigger rights to terminate all financial trades with such counterparty; and (3) netting of settlement amounts reduces EAC s credit exposure to a given counterparty in the event of close-out. EAC s accounting policy is to not offset fair value amounts recorded in the accompanying Consolidated Balance Sheets for derivative instruments.

Interest Rate Swaps

ENP uses derivative instruments in the form of interest rate swaps, which hedge risk related to interest rate fluctuation, whereby it converts the interest due on certain floating rate debt under its revolving credit facility to a weighted average fixed rate. The following table summarizes ENP s open interest rate swaps as of June 30, 2009, all of which were entered into with Bank of America, N.A.:

Term	Notional Amount (in thousands)	Fixed Rate	Floating Rate
July 2009 - Jan. 2011	$ 50,000	3.1610%	1-month LIBOR
July 2009 - Jan. 2011	25,000	2.9650%	1-month LIBOR
July 2009 - Jan. 2011	25,000	2.9613%	1-month LIBOR
July 2009 - Mar. 2012	50,000	2.4200%	1-month LIBOR

The actual gains or losses ENP will realize from its interest rate swaps may vary significantly from the deferred loss recorded in accumulated other comprehensive loss due to the fluctuation of interest rates.

Current Period Impact

EAC recognized derivative fair value gains and losses related to: (1) ineffectiveness on derivative contracts designated as hedges; (2) changes in the fair market value of derivative contracts not designated as hedges; (3)

settlements on derivative contracts not designated as hedges; and (4) premium amortization. The following table summarizes the components of Derivative fair value loss for the periods indicated:

	Three months ended June 30,		Six months ended June 30,	
	2009	**2008**	**2009**	**2008**
	(in thousands)			
Ineffectiveness	$ 6	$ 39	$ (34)	$ (343)
Mark-to-market loss	78,082	219,433	280,993	265,048
Premium amortization	6,764	17,293	84,719	32,806
Settlements	(23,746)	19,625	(353,163)	24,017
Total derivative fair value loss	$ 61,106	$ 256,390	$ 12,515	$ 321,528

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In March 2009, EAC elected to monetize certain of its 2009 oil derivative contracts and received proceeds of approximately $190.4 million from these settlements, which were used to reduce outstanding borrowings under EAC s revolving credit facility.

Accumulated Other Comprehensive Loss

At June 30, 2009 and December 31, 2008, accumulated other comprehensive loss consisted entirely of deferred losses, net of tax, on ENP s interest rate swaps of $1.4 million and $1.7 million, respectively. During the twelve months ending June 30, 2010, EAC expects to reclassify $3.3 million of deferred losses associated with ENP s interest rate swaps from accumulated other comprehensive loss to interest expense.

Tabular Disclosures of Fair Value Measurements

The following table summarizes the fair value of EAC s derivative contracts as of the dates indicated (in thousands):

	Asset Derivatives				Liability Derivatives			
	June 30, 2009		December 31, 2008		June 30, 2009		December 31, 2008	
	Balance Sheet Location	Fair Value	Balance Sheet Location	Fair Value	Balance Sheet Location	Fair Value	Balance Sheet Location	Fair Value
Derivatives not designated as hedging instruments under SFAS 133								
Commodity derivative contracts	Derivatives - current	$ 53,204	Derivatives - current	$ 349,344	Derivatives - current	$ 10,037	Derivatives - current	$
Commodity derivative contracts	Derivatives - noncurrent	48,151	Derivatives - noncurrent	38,497	Derivatives - noncurrent	18,286	Derivatives - noncurrent	229
Total derivatives not designated as hedging instruments under SFAS 133		$ 101,355		$ 387,841		$ 28,323		$ 229
Derivatives designated as hedging instruments under SFAS 133								
Interest rate swaps	Derivatives - current	$	Derivatives - current	$	Derivatives - current	$ 3,272	Derivatives - current	$ 1,297

Interest rate swaps	Derivatives - noncurrent		Derivatives - noncurrent		Derivatives - noncurrent	553	Derivatives - noncurrent	3,262
Total derivatives designated as hedging instruments under SFAS 133		$		$		$ 3,825		$ 4,559
Total derivatives		$ 101,355		$ 387,841		$ 32,148		$ 4,788

The following table summarizes the effect of derivative instruments not designated as hedges under SFAS 133 on the Consolidated Statements of Operations for the periods indicated (in thousands):

		Amount of Loss Recognized In Income			
Derivatives Not Designated as	**Location of Loss Recognized**	**Three Months Ended June 30,**		**Six Months Ended June 30,**	
Hedges Under SFAS 133	**In Income**	**2009**	**2008**	**2009**	**2008**
Commodity derivative contracts	Derivative fair value loss	$ 61,100	$ 256,351	$ 12,549	$ 321,871

The following tables summarize the effect of derivative instruments designated as hedges under SFAS 133 on the Consolidated Statements of Operations for the periods indicated (in thousands):

Derivatives Designated as Hedges Under SFAS 133	**Amount of Gain Recognized in OCI (Effective Portion) Three months ended June 30, 2009**	**2008**	**Location of Loss (Gain) Reclassified from Accumulated OCI into Income (Effective Portion)**	**Amount of Loss Reclassified from Accumulated OCI into Income (Effective Portion) Three months ended June 30, 2009**	**2008**	**Location of Loss (Gain) Recognized in Income as Ineffective**	**Amount of Loss Recognized In Income as Ineffective Three months ended June 30, 2009**	**2008**
Interest rate swaps	$ 267	$ 942	Interest expense	$ 922	$ 125	Derivative fair value loss	$ 6	$ 39
Commodity derivative contracts			Oil and natural gas revenues		1,428			
Total	$ 267	$ 942		$ 922	$ 1,553		$ 6	$ 39

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Derivatives Designated as Hedges Under SFAS 133	Amount of Loss Recognized in OCI (Effective Portion) Six months ended June 30, 2009	2008	Location of Loss (Gain) Reclassified from Accumulated OCI into Income (Effective Portion)	Amount of Loss Reclassified from Accumulated OCI into Income (Effective Portion) Six months ended June 30, 2009	2008	Location of Loss (Gain) Recognized in Income as Ineffective	Amount of Gain Recognized In Income as Ineffective Six months ended June 30, 2009	2008
Interest rate swaps	$ 1,489	$ 762	Interest expense	$ 1,803	$ 108	Derivative fair value loss	$ 34	$ 343
Commodity derivative contracts			Oil and natural gas revenues		2,857			
Total	$ 1,489	$ 762		$ 1,803	$ 2,965		$ 34	$ 343

Fair Value Hierarchy

As discussed in Note 2. Basis of Presentation, EAC adopted FSP FAS 157-2 on January 1, 2009, as it relates to nonfinancial assets and liabilities. 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 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-based 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 methodology based upon credit ratings and forward interest rate yield curves obtained from independent pricing services reflecting broker market quotes.

Level 3 EAC s oil and natural gas calls, puts, and short puts are average value options, which are not exchange-traded contracts. Settlement is determined by the average underlying price over a predetermined period of time. EAC uses both observable and unobservable inputs in a Black-Scholes valuation model to determine fair value. Accordingly, these derivative instruments are classified within the Level 3 valuation hierarchy. The observable inputs of EAC s valuation model include: (1) current market and contractual prices for the underlying instruments; (2) quoted forward prices for oil and natural gas; and (3) interest rates, such as a LIBOR curve for a term similar to the commodity derivative contract. The unobservable inputs of EAC s valuation model include volatility. The implied volatilities for EAC s calls, puts, and short puts with comparable strike prices are based on the settlement values from certain exchange-traded contracts. The implied volatilities for calls, puts, and short puts where there are no exchange-traded contracts with the same strike price are extrapolated from exchange-traded implied volatilities by an independent party.

EAC adjusts the valuations from the valuation model for nonperformance risk, using management s estimate of the counterparty s credit quality for asset positions and EAC s credit quality for liability positions. EAC uses the multiple sources of third-party credit data in determining counterparty nonperformance risk, including credit default swaps. EAC considers the impact of netting and offset provisions in the agreements on counterparty credit risk, including whether the position with the counterparty is a net asset or net liability. There have been no changes in the valuation techniques used to measure the fair value of EAC s oil and natural gas calls, puts, or short puts during 2009.

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The following table sets forth EAC s assets and liabilities that were accounted for at fair value on a recurring basis as of June 30, 2009:

Description	Asset (Liability) at June 30, 2009	Fair Value Measurements at Reporting Date Using: 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	$ (14,733)	$	$ (14,733)	$
Oil derivative contracts floors and caps	62,049			62,049
Natural gas derivative contracts swaps	4,693		4,693	
Natural gas derivative contracts floors and caps	21,023			21,023
Interest rate swaps	(3,825)		(3,825)	
Total	$ 69,207	$	$ (13,865)	$ 83,072

The following table summarizes the changes in the fair value of EAC s Level 3 assets and liabilities for the six months ended June 30, 2009:

	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, 2009	$ 337,335	$ 12,741	$ 350,076
Total gains (losses):			
Included in earnings	13,106	21,840	34,946
Purchases, issuances, and settlements	(288,392)	(13,558)	(301,950)
Balance at June 30, 2009	$ 62,049	$ 21,023	$ 83,072
	$ 13,106	$ 21,840	$ 34,946

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

Since EAC does not use hedge accounting for its commodity derivative contracts, all gains and losses on its Level 3 assets and liabilities are included in Derivative fair value loss in the accompanying Consolidated Statements of Operations. All fair values have been adjusted for non-performance risk, resulting in a reduction of the net commodity derivative asset of approximately $0.8 million as of June 30, 2009.

EAC s assessment of the significance of a particular input to the fair value measurement requires judgment and may affect the valuation of the nonfinancial 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 assets and liabilities that are accounted for at fair value on a nonrecurring basis:

Level 3 Fair values of asset retirement obligations are determined using discounted cash flow methodologies based on inputs, such as plugging costs and reserve lives, which are not readily available in public markets. See Note 6. Asset Retirement Obligations for additional discussion of EAC s asset retirement obligations.

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The following table sets forth EAC s assets and liabilities that were measured at fair value on a nonrecurring basis as of June 30, 2009:

		Fair Value Measurements Using			
Description	**Liability at June 30, 2009**	**Quoted Prices in Active Markets for Identical Assets (Level 1)**	**Significant Other Observable Inputs (Level 2)**	**Significant Unobservable Inputs (Level 3)**	**Total Gains (Losses)**
			(in thousands)		
Asset retirement obligations	$255	$	$	$ 255	$

Note 6. Asset Retirement Obligations

Asset retirement obligations relate to future plugging and abandonment expenses on oil and natural gas properties and related facilities disposal. The following table summarizes the changes in EAC s asset retirement obligations for the six months ended June 30, 2009 (in thousands):

Future abandonment liability at January 1, 2009	$ 49,569
Wells drilled	194
Acquisition of properties	61
Divestiture	(221)
Accretion of discount	1,181
Plugging and abandonment costs incurred	(663)
Revision of previous estimates	(469)
Future abandonment liability at June 30, 2009	$ 49,652

As of June 30, 2009, $48.0 million of EAC s asset retirement obligations were long-term and recorded in Future abandonment cost, net of current portion and $1.7 million were current and included in Other current liabilities in the accompanying Consolidated Balance Sheets. Approximately $4.6 million of the future abandonment liability represents the estimated cost for decommissioning ENP s Elk Basin natural gas processing plant. ENP expects to continue reserving additional amounts based on the estimated timing to cease operations of the natural gas processing plant.

As of June 30, 2009 and December 31, 2008, EAC held $9.3 million and $9.2 million, respectively, in escrow, which is to be released only for reimbursement of actual plugging and abandonment costs incurred on its Bell Creek properties, which is included in other long-term assets in the accompanying Consolidated Balance Sheets.

Note 7. Long-Term Debt

Long-term debt consisted of the following as of the dates indicated:

	Maturity Date	**June 30, 2009**	**December 31, 2008**

		(in thousands)	
Revolving credit facilities	3/7/2012	$ 370,000	$ 725,000
6.25% Senior Subordinated Notes	4/15/2014	150,000	150,000
6.0% Senior Subordinated Notes, net of unamortized discount of $3,708 and $3,960, respectively	7/15/2015	296,292	296,040
9.5% Senior Subordinated Notes, net of unamortized discount of $17,201 and zero, respectively	5/1/2016	207,799	
7.25% Senior Subordinated Notes, net of unamortized discount of $1,179 and $1,229, respectively	12/1/2017	148,821	148,771
Total		$ 1,172,912	$ 1,319,811

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Encore Acquisition Company Senior Secured Credit Agreement

EAC is a party to a five-year amended and restated credit agreement dated March 7, 2007 (as amended, the EAC Credit Agreement). The EAC Credit Agreement matures on March 7, 2012. Effective March 10, 2009, EAC amended the EAC Credit Agreement to, among other things, increase the interest rate margins and commitment fees applicable to loans made under the EAC Credit Agreement. The EAC Credit Agreement provides for revolving credit loans to be made to EAC from time to time and letters of credit to be issued from time to time for the account of EAC or any of its 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 on April 1 and October 1 and upon requested special redeterminations. In March 2009, the borrowing base of the EAC Credit Agreement was reaffirmed at $1.1 billion before a reduction of $200 million solely as a result of the monetization of certain of EAC s 2009 oil derivative contracts during the first quarter of 2009. In April 2009, the borrowing base of the EAC Credit Agreement was reduced by $75 million as a result of EAC s issuance of senior subordinated notes. As of June 30, 2009, the borrowing base was $825 million and there were $175 million of outstanding borrowings and $650 million of borrowing capacity under the EAC Credit Agreement.

EAC incurs 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 commitment fee percentage under the EAC Credit Agreement:

Ratio of Total Outstanding Borrowings to Borrowing Base	Commitment Fee Percentage
Less than .90 to 1	0.375%
Greater than or equal to .90 to 1	0.500%

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

Loans under the EAC Credit Agreement are subject to varying rates of interest based on (1) the total outstanding borrowings in relation to the borrowing base and (2) whether the loan is a Eurodollar loan or a base rate loan. Eurodollar loans under the EAC Credit Agreement bear interest at the Eurodollar rate plus the applicable margin indicated in the following table, and base rate loans under the EAC Credit Agreement 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	1.750%	0.500%
Greater than or equal to .50 to 1 but less than .75 to 1	2.000%	0.750%
Greater than or equal to .75 to 1 but less than .90 to 1	2.250%	1.000%
Greater than or equal to .90 to 1	2.500%	1.250%

The Eurodollar rate for any interest period (either one, two, three, or six months, as selected by EAC) is the rate equal to the British Bankers Association LIBOR Rate for deposits in dollars for a similar interest period. The Base Rate is calculated as the highest of: (1) the annual rate of interest announced by Bank of America, N.A. as its prime rate ; (2) the federal funds effective rate plus 0.5 percent; or (3) except during a LIBOR Unavailability Period, the

Eurodollar rate (for dollar deposits for a one-month term) for such day plus 1.0 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, among others, include:

- a prohibition against incurring debt, subject to permitted exceptions;

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

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- a restriction on creating liens on the assets of EAC 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 EAC maintain a ratio of consolidated current assets to consolidated current liabilities of not less than 1.0 to 1.0; and
- a requirement that EAC maintain a ratio of consolidated EBITDA to the sum of consolidated net interest expense plus letter of credit fees of not less than 2.5 to 1.0.

As of June 30, 2009, EAC was in compliance with all covenants of the EAC Credit Agreement.

The EAC Credit Agreement contains customary events of default including, among others, the following:

- failure to pay principal on any loan when due;
- failure to pay accrued interest on any loan or fees when due and such failure continues for more than three days;
- failure to observe or perform covenants and agreements contained in the OLLC Credit Agreement, subject in some cases to a 30-day grace period after discovery or notice of such failure;
- failure to make a payment when due on any other debt in a principal amount equal to or greater than $15 million or any other event or condition occurs which results in the acceleration of such debt or entitles the holder of such debt to accelerate the maturity of such debt;
- the commencement of liquidation, reorganization, or similar proceedings with respect to OLLC or any guarantor under bankruptcy or insolvency law, or the failure of OLLC or any guarantor generally to pay its debts as they become due;
- the entry of one or more judgments in excess of $15 million (to the extent not covered by insurance) and such judgment(s) remain unsatisfied and unstayed for 30 days;
- the occurrence of certain ERISA events involving an amount in excess of $15 million;
- there cease to exist liens covering at least 80 percent of the borrowing base properties; or
- the occurrence of a change in control.

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.

Encore Energy Partners Operating LLC Credit Agreement

Encore Energy Partners Operating LLC (OLLC), a Delaware limited liability company and wholly owned subsidiary of ENP, is a party to a five-year credit agreement dated March 7, 2007 (as amended, the OLLC Credit

Agreement). The OLLC Credit Agreement matures on March 7, 2012. Effective March 10, 2009, OLLC amended the OLLC Credit Agreement to, among other things, increase the interest rate margins and commitment fees applicable to loans made under the OLLC Credit Agreement. 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.

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 on April 1 and October 1 and upon requested special redeterminations. In March 2009, the borrowing base under the OLLC Credit Agreement was redetermined with no change. As of June 30, 2009, the borrowing base was $240 million and there were $195 million of outstanding borrowings and $45 million of borrowing capacity under the OLLC Credit Agreement.

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OLLC 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 commitment fee percentage under the OLLC Credit Agreement:

Ratio of Total Outstanding Borrowings to Borrowing Base	Commitment Fee Percentage
Less than .90 to 1	0.375%
Greater than or equal to .90 to 1	0.500%

OLLC s obligations under the OLLC Credit Agreement are secured by a first-priority security interest in substantially all of OLLC s proved oil and natural gas reserves and in the equity interests of OLLC and its restricted subsidiaries. In addition, OLLC s obligations under the OLLC Credit Agreement are guaranteed by ENP and OLLC s restricted subsidiaries. Obligations under the OLLC Credit Agreement are non-recourse to EAC and its 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 under the OLLC Credit Agreement bear interest at the Eurodollar rate plus the applicable margin indicated in the following table, and base rate loans under the OLLC Credit Agreement 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	1.750%	0.750%
Greater than or equal to .50 to 1 but less than .75 to 1	2.000%	0.750%
Greater than or equal to .75 to 1 but less than .90 to 1	2.250%	1.000%
Greater than or equal to .90 to 1	2.500%	1.250%

The Eurodollar Rate for any interest period (either one, two, three, or six months, as selected by ENP) is the rate equal to the British Bankers Association LIBOR Rate for deposits in dollars for a similar interest period. The Base Rate is calculated as the highest of: (1) the annual rate of interest announced by Bank of America, N.A. as its prime rate ; (2) the federal funds effective rate plus 0.5 percent; or (3) except during a LIBOR Unavailability Period, the Eurodollar rate (for dollar deposits for a one-month term) for such day plus 1.0 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, among others, include:

- 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 OLLC s 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 ENP and OLLC maintain a ratio of consolidated current assets to consolidated current liabilities of not less than 1.0 to 1.0;

a requirement that ENP and OLLC maintain a ratio of consolidated EBITDA 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 ENP and OLLC maintain a ratio of consolidated EBITDA to consolidated senior interest expense of not less than 2.5 to 1.0; and

a requirement that ENP and OLLC maintain a ratio of consolidated funded debt (excluding certain related party debt) to consolidated adjusted EBITDA of not more than 3.5 to 1.0.

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As of June 30, 2009, OLLC was in compliance with all covenants of the OLLC Credit Agreement.

The OLLC Credit Agreement contains customary events of default including, among others, the following:

- failure to pay principal on any loan when due;
- failure to pay accrued interest on any loan or fees when due and such failure continues for more than three days;
- failure to observe or perform covenants and agreements contained in the OLLC Credit Agreement, subject in some cases to a 30-day grace period after discovery or notice of such failure;
- failure to make a payment when due on any other debt in a principal amount equal to or greater than $3 million or any other event or condition occurs which results in the acceleration of such debt or entitles the holder of such debt to accelerate the maturity of such debt;
- the commencement of liquidation, reorganization, or similar proceedings with respect to OLLC or any guarantor under bankruptcy or insolvency law, or the failure of OLLC or any guarantor generally to pay its debts as they become due;
- the entry of one or more judgments in excess of $3 million (to the extent not covered by insurance) and such judgment(s) remain unsatisfied and unstayed for 30 days;
- the occurrence of certain ERISA events involving an amount in excess of $3 million;
- there cease to exist liens covering at least 80 percent of the borrowing base properties; or
- the occurrence of a change in control.

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.

9.50% Senior Subordinated Notes due 2016 (the 9.5% Notes)

In April 2009, EAC issued $225 million of its 9.5% Notes at 92.228 percent of par value. EAC received net proceeds of approximately $202.5 million, after deducting the underwriters discounts and commissions of $4.5 million, in the aggregate, and offering expenses of approximately $0.6 million. EAC used the net proceeds to reduce outstanding borrowings under the EAC Credit Agreement. Interest on the 9.5% Notes is due semi-annually on May 1 and November 1, beginning November 1, 2009. The 9.5% Notes mature on May 1, 2016.

Note 8. Stockholders Equity

Stock Repurchase Program

In October 2008, EAC announced that its Board of Directors (the Board) approved a share repurchase program authorizing EAC to repurchase up to $40 million of its common stock. As of June 30, 2009, 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 share repurchase program. During the three and six months ended June 30, 2009, EAC did not repurchase any shares of its outstanding common stock under the share repurchase program. As of June 30, 2009, approximately $22.8 million of EAC s common stock remained authorized for repurchase.

Stock Option Exercises and Restricted Stock Vestings

During the three and six months ended June 30, 2009, certain employees exercised 19,748 options and 21,484 options, respectively, for which EAC received proceeds of approximately $0.4 million and $0.4 million, respectively. During the three and six months ended June 30, 2009, certain employees elected to satisfy minimum tax withholding obligations in conjunction with the vesting of restricted stock by directing EAC to withhold 466 shares and 111,819 shares of common stock, respectively, which are accounted for as treasury stock until they are formally retired.

Issuance of ENP Common Units

In May 2009, ENP issued 2,760,000 common units at a price to the public of $15.60 per unit. As a result, EAC s ownership percentage of ENP s common units decreased from approximately 63 percent to approximately 58 percent. Additionally, EAC increased Noncontrolling interest and Additional paid-in capital on the accompanying Consolidated Balance Sheets by $31.2 million and $9.3 million, respectively, to recognize the net proceeds from the issuance of ENP s common units.

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Note 9. Income Taxes

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

	Six months ended June 30, 2009	Six months ended June 30, 2008
	(in thousands)	
Federal:		
Current	$ 80	$ (20,110)
Deferred	34,568	22,877
Total federal	34,648	2,767
State, net of federal benefit:		
Current	(1,151)	(4,057)
Deferred	2,946	3,879
Total state	1,795	(178)
Income tax benefit	$ 36,443	$ 2,589

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

	Six months ended June 30, 2009	Six months ended June 30, 2008
	(in thousands)	
Loss before income taxes	$ (103,866)	$ (21,977)
Income taxes at the Federal statutory rate	$ 36,353	$ 7,692
State income taxes, net of federal benefit	1,912	165
Tax on income attributable to noncontrolling interest	(4,512)	(5,211)
Permanent and other	2,690	(57)
Income tax benefit	$ 36,443	$ 2,589

As of June 30, 2009 and December 31, 2008, all of EAC s tax positions met the more-likely-than-not threshold prescribed by FASB Interpretation 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 in Interest expense and penalties related to income taxes in Other expense on its Consolidated Statements of Operations. During the six months ended June 30, 2009 and 2008, EAC recorded only a nominal amount of interest and penalties on certain tax positions.

Note 10. Earnings Per Share

As discussed in Note 2. Basis of Presentation, EAC adopted FSP EITF 03-6-1 on January 1, 2009, and all periods presented have been restated to calculate EPS in accordance with this pronouncement. Under the two-class method of calculating EPS, earnings are allocated to participating securities as if all the earnings for the period had been distributed. A participating security is any security that contains nonforfeitable rights to dividends or dividend equivalents paid to common stockholders. For purposes of calculating EPS, unvested restricted stock awards are considered participating securities. EPS is calculated by dividing the common stockholders interest in net income (loss), after deducting the interests of participating securities, by the weighted average shares outstanding. For the three and six months ended June 30, 2008, basic EPS and diluted EPS were unaffected by the adoption of FSP EITF 03-6-1.

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The following table reflects the allocation of net loss to EAC s common stockholders and EPS computations for the periods indicated:

	Three months ended June 30, 2009	Three months ended June 30, 2008 (c)	Six months ended June 30, 2009	Six months ended June 30, 2008 (c)
	(in thousands, except per share amounts)			
Basic Earnings Per Share				
Numerator:				
Undistributed net loss attributable to EAC	$ (46,975)	$ (35,720)	$ (54,531)	$ (4,500)
Participation rights of unvested restricted stock in undistributed earnings (a)				
Basic undistributed net loss attributable to EAC common shares	$ (46,975)	$ (35,720)	$ (54,531)	$ (4,500)
Denominator:				
Basic weighted average shares outstanding	51,849	52,344	51,769	52,571
Basic EPS attributable to EAC common shares	$ (0.91)	$ (0.68)	$ (1.05)	$ (0.09)
Diluted Earnings Per Share				
Numerator:				
Basic undistributed net loss attributable to EAC common shares	$ (46,975)	$ (35,720)	$ (54,531)	$ (4,500)
Denominator:				
Basic weighted average shares outstanding	51,849	52,344	51,769	52,571
Effect of dilutive options (b)				
Diluted weighted average shares outstanding	51,849	52,344	51,769	52,571
Diluted EPS attributable to EAC common shares	$ (0.91)	$ (0.68)	$ (1.05)	$ (0.09)

(a) Unvested restricted stock has no contractual obligation to absorb losses of EAC. Therefore, for the three and six months ended June 30, 2009, 923,829 shares of restricted stock were outstanding but excluded from the EPS calculations because their effect would have been antidilutive and for the three and six months ended June 30, 2008, 966,740 shares of restricted stock were outstanding but excluded from the EPS calculations because their effect would have been antidilutive. Please read Note 11. Incentive Stock Plans for additional discussion of restricted stock.

(b) For the three and six months ended June 30, 2009, options to purchase 1,732,383 shares of common stock were outstanding but excluded from the EPS calculations because their effect would have been antidilutive. For the three and six months ended June 30, 2008, options to purchase 1,524,107 shares of common stock were outstanding but excluded from the EPS calculations because their effect would have been antidilutive. Please read Note 11. Incentive Stock Plans for additional discussion of stock options.

(c) For the three and six months ended June 30, 2008, EAC considered the impact of the conversion of vested management incentive units held by certain executive officers of GP LLC. The conversion of the management incentive units into limited partner units of ENP would reduce EAC s share of ENP s earnings and therefore, the impact of this conversion was excluded from the diluted EPS calculations because the effect would have been antidilutive. Please read Note 16. ENP for additional discussion of ENP s management incentive units.

Note 11. 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 outstanding awards granted 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 stockholder 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 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 Special Stock Award Committee whose sole member is Jon S. Brumley, EAC s Chief Executive Officer and President. The Special 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 total number of shares of EAC s common stock reserved for issuance pursuant to the 2008 Plan is 2,400,000, of which no more than 1,600,000 are available for grants of full value stock awards, such as restricted stock or stock units. As of June 30, 2009, there were 1,715,670 shares available for issuance under the 2008 Plan, of which 1,180,913 are available for grants of full value stock awards. 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.

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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.

During the six months ended June 30, 2009 and 2008, EAC recorded non-cash stock-based compensation expense related to its incentive stock plans of $6.7 million and $4.1 million, respectively, which was allocated to LOE and general and administrative expense in the accompanying Consolidated Statements of Operations based on the allocation of the respective employees cash compensation. During the six months ended June 30, 2009 and 2008, EAC also capitalized $1.2 million and $1.0 million, respectively, of non-cash stock-based compensation expense related to its incentive stock plans as a component of Proved properties in the accompanying Consolidated Balance Sheets. During the six months ended June 30, 2009 and 2008, EAC recognized income tax benefits related to its incentive stock plans of $2.5 million and $1.5 million, respectively.

Please read Note 16. ENP for a discussion of ENP s unit-based compensation plans.

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 six months ended June 30, 2009 and 2008 was estimated on the grant date using a Black-Scholes option valuation model based on the following assumptions:

	Six months ended June 30, 2009	Six months ended June 30, 2008
Expected volatility	51.9%	33.7%
Expected dividend yield	0.0%	0.0%
Expected term (in years)	6.25	6.25
Risk-free interest rate	2.1%	3.0%
Weighted-average fair value per share	$15.81	$13.15

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. 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.

The following table summarizes the changes in EAC s outstanding options for the six months ended June 30, 2009:

	Number of Options	Weighted Average Strike Price	Weighted Average Remaining Contractual Term	Aggregate Intrinsic Value (in thousands)
Outstanding at January 1, 2009	1,497,413	$18.02		

Granted	269,417	30.55		
Forfeited or expired	(12,963)	30.91		
Exercised	(21,484)	19.42		
Outstanding at June 30, 2009	1,732,383	19.86	5.4	$19,527
Exercisable at June 30, 2009	1,299,677	16.25	4.1	19,145

The total intrinsic value of options exercised during the six months ended June 30, 2009 and 2008 was $0.3 million and $0.6 million, respectively. During each of the six months ended June 30, 2009 and 2008, EAC received proceeds from the exercise of stock options of $0.4 million. During the six months ended June 30, 2009 and 2008, EAC recognized income tax benefits related to

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stock options of $40 thousand and $0.2 million, respectively. At June 30, 2009, EAC had $3.0 million of total unrecognized compensation cost related to unvested stock options, which is expected to be recognized over a weighted average period of 2.3 years.

Restricted Stock

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 six months ended June 30, 2009, EAC recognized expense related to restricted stock of $5.1 million and recognized an income tax provision related to the vesting of restricted stock of $0.4 million. During the six months ended June 30, 2008, EAC recognized expense related to restricted stock of $3.4 million and recognized an income tax benefit related to the vesting of restricted stock of $0.8 million. The following table summarizes the changes in EAC s unvested restricted stock awards for the six months ended June 30, 2009:

	Number of Shares	Weighted Average Grant Date Fair Value
Outstanding at January 1, 2009	938,407	$30.67
Granted	412,449	30.52
Vested	(408,478)	29.25
Forfeited	(18,549)	30.27
Outstanding at June 30, 2009	923,829	31.20

As of June 30, 2009, there were 704,809 shares of unvested restricted stock, 189,067 shares of which were granted during 2009, in which the vesting is dependent only on the passage of time and continued employment. Additionally, as of June 30, 2009, there were 219,020 shares of unvested restricted stock, all of which were granted during 2009, in which the vesting is dependent not only on the passage of time and continued employment, but also on the achievement of certain performance measures.

None of EAC s unvested restricted stock awards are subject to variable accounting. During the six months ended June 30, 2009 and 2008, there were 408,478 shares and 235,086 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 111,819 shares and 28,193 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 the accompanying consolidated financial statements. The total fair value of restricted stock that vested during the six months ended June 30, 2009 and 2008 was $11.0 million and $8.2 million, respectively. As of June 30, 2009, EAC had $12.7 million of total unrecognized compensation cost related to unvested restricted stock, which is expected to be recognized over a weighted average period of 3.1 years.

Note 12. Comprehensive Loss

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

	Three months ended June 30,		Six months ended June 30,	
	2009	2008	2009	2008
	(in thousands)			
Consolidated net loss	$ (61,520)	$ (50,702)	$ (67,423)	$ (19,388)
		907		1,786

Amortization of deferred loss on commodity derivative contracts				
Change in deferred hedge loss on interest rate swaps	977	1,588	432	417
Consolidated comprehensive loss	(60,543)	(48,207)	(66,991)	(17,185)
Less: comprehensive loss attributable to noncontrolling interest	14,223	14,161	12,774	14,571
Comprehensive loss attributable to EAC	$ (46,320)	$ (34,046)	$ (54,217)	$ (2,614)

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Note 13. Financial Statements of Subsidiary Guarantors

Certain of EAC s wholly owned subsidiaries are 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. The following Condensed Consolidating Balance Sheets as of June 30, 2009 and December 31, 2008, Condensed Consolidating Statements of Operations and Comprehensive Income (Loss) for the three and six months ended June 30, 2009 and 2008, and Condensed Consolidating Statements of Cash Flows for the six months ended June 30, 2009 and 2008 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 June 30, 2009, EAC s guarantor subsidiaries were:

EAP Properties, Inc.;

EAP Operating, LLC;

Encore Operating, L.P.; and

Encore Operating Louisiana, LLC.

As of June 30, 2009, EAC s non-guarantor subsidiaries were:

ENP;

OLLC;

GP LLC;

Encore Partners GP Holdings LLC;

Encore Partners LP Holdings LLC;

Encore Energy Partners Finance Corporation; and

Encore Clear Fork Pipeline LLC.

All intercompany investments in, loans due to/from, subsidiary equity, 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.

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ENCORE ACQUISITION COMPANY
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS Continued
(unaudited)
CONDENSED CONSOLIDATING BALANCE SHEET
June 30, 2009
(in thousands)

	Parent	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Eliminations	Consolidated Total
ASSETS					
Current assets:					
Cash and cash equivalents	$ 44	$ 35,724	$ 72	$	$ 35,840
Other current assets	5,223	141,923	56,752	(2,839)	201,059
Total current assets	5,267	177,647	56,824	(2,839)	236,899
Properties and equipment, at cost successful efforts method:					
Proved properties, including wells and related equipment		3,130,887	612,930		3,743,817
Unproved properties		114,118	50		114,168
Accumulated depletion, depreciation, and amortization		(779,057)	(134,964)		(914,021)
		2,465,948	478,016		2,943,964
Other property and equipment, net		10,479	461		10,940
Other assets, net	16,207	178,961	33,998		229,166
Investment in subsidiaries	2,733,354	3,325		(2,736,679)	
Total assets	$ 2,754,828	$ 2,836,360	$ 569,299	$ (2,739,518)	$ 3,420,969
LIABILITIES AND EQUITY					
Current liabilities	$ 93,828	$ 167,618	$ 31,317	$ (2,839)	$ 289,924
Deferred taxes	408,432	9	73		408,514
Long-term debt	977,912		195,000		1,172,912
Other liabilities		82,886	16,607		99,493
Total liabilities	1,480,172	250,513	242,997	(2,839)	1,970,843

Commitments and contingencies (see Note 14)					
Total equity	1,274,656	2,585,847	326,302	(2,736,679)	1,450,126
Total liabilities and equity	$ 2,754,828	$ 2,836,360	$ 569,299	$ (2,739,518)	$ 3,420,969

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ENCORE ACQUISITION COMPANY
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS Continued
(unaudited)
CONDENSED CONSOLIDATING BALANCE SHEET
December 31, 2008
(in thousands)

	Parent	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Eliminations	Consolidated Total
ASSETS					
Current assets:					
Cash and cash equivalents	$ 607	$ 813	$ 619	$	$ 2,039
Other current assets	29,004	421,392	90,797	(2,302)	538,891
Total current assets	29,611	422,205	91,416	(2,302)	540,930
Properties and equipment, at cost successful efforts method:					
Proved properties, including wells and related equipment		3,016,937	521,522		3,538,459
Unproved properties		124,272	67		124,339
Accumulated depletion, depreciation, and amortization		(670,991)	(100,573)		(771,564)
		2,470,218	421,016		2,891,234
Other property and equipment, net		11,877	562		12,439
Other assets, net	12,846	129,482	46,264		188,592
Investment in subsidiaries	2,976,208	(12,865)		(2,963,343)	
Total assets	$ 3,018,665	$ 3,020,917	$ 559,258	$ (2,965,645)	$ 3,633,195
LIABILITIES AND EQUITY					
Current liabilities	$ 118,089	$ 215,640	$ 20,825	$ (2,302)	$ 352,252
Deferred taxes	416,637		278		416,915
Long-term debt	1,169,811		150,000		1,319,811
Other liabilities		48,000	12,969		60,969
Total liabilities	1,704,537	263,640	184,072	(2,302)	2,149,947

Commitments and contingencies (see Note 14)					
Total equity	1,314,128	2,757,277	375,186	(2,963,343)	1,483,248
Total liabilities and equity	$ 3,018,665	$ 3,020,917	$ 559,258	$ (2,965,645)	$ 3,633,195

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ENCORE ACQUISITION COMPANY
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS Continued
(unaudited)
CONDENSED CONSOLIDATING STATEMENT OF OPERATIONS AND COMPREHENSIVE LOSS
For the Three Months Ended June 30, 2009
(in thousands)

	Parent	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Eliminations	Consolidated Total
Revenues:					
Oil	$	$ 110,495	$ 23,182	$	$ 133,677
Natural gas		25,531	3,955		29,486
Marketing		206	109		315
Total revenues		136,232	27,246		163,478
Expenses:					
Production:					
Lease operating		33,502	6,949		40,451
Production, ad valorem, and severance taxes		13,971	3,062		17,033
Depletion, depreciation, and amortization		63,140	11,294		74,434
Exploration		15,916	18		15,934
General and administrative	4,237	7,958	2,810	(1,226)	13,779
Marketing		454	61		515
Derivative fair value loss		23,666	37,440		61,106
Other operating	43	14,134	658		14,835
Total expenses	4,280	172,741	62,292	(1,226)	238,087
Operating loss	(4,280)	(36,509)	(35,046)	1,226	(74,609)
Other income (expenses):					
Interest	(16,775)		(2,351)		(19,126)
Equity loss from subsidiaries	(57,646)	(11,918)		69,564	
Other	(33)	1,915	1	(1,226)	657
Total other expenses	(74,454)	(10,003)	(2,350)	68,338	(18,469)
Loss before income taxes	(78,734)	(46,512)	(37,396)	69,564	(93,078)
Income tax benefit (provision)	31,758		(200)		31,558
Consolidated net loss	(46,976)	(46,512)	(37,596)	69,564	(61,520)

Change in deferred hedge loss on interest rate swaps, net of tax	(384)		1,361		977
Comprehensive loss	$ (47,360)	$ (46,512)	$ (36,235)	$ 69,564	$ (60,543)

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

	Parent	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Eliminations	Consolidated Total
Revenues:					
Oil	$	$ 239,783	$ 47,141	$	$ 286,924
Natural gas		56,081	11,808		67,889
Marketing		1,618	903		2,521
Total revenues		297,482	59,852		357,334
Expenses:					
Production:					
Lease operating		33,775	6,922		40,697
Production, ad valorem, and severance taxes		29,261	5,782		35,043
Depletion, depreciation, and amortization		41,811	9,215		51,026
Exploration		11,555	38		11,593
General and administrative	3,911	5,830	2,933	(1,115)	11,559
Marketing		2,116	1,609		3,725
Derivative fair value loss		179,962	76,428		256,390
Other operating	42	2,853	331		3,226
Total expenses	3,953	307,163	103,258	(1,115)	413,259
Operating loss	(3,953)	(9,681)	(43,406)	1,115	(55,925)
Other income (expenses):					
Interest	(14,876)		(1,909)		(16,785)
Equity loss from subsidiaries	(38,923)	(15,800)		54,723	
Other	(85)	1,821	65	(1,115)	686
Total other expenses	(53,884)	(13,979)	(1,844)	53,608	(16,099)
Loss before income taxes	(57,837)	(23,660)	(45,250)	54,723	(72,024)
Income tax benefit (provision)	21,151	(81)	252		21,322
Consolidated net loss	(36,686)	(23,741)	(44,998)	54,723	(50,702)

Amortization of deferred loss on commodity derivative contracts, net of tax	(522)	1,429			907
Change in deferred hedge gain on interest rate swaps, net of tax	(647)		2,235		1,588
Comprehensive loss	$ (37,855)	$ (22,312)	$ (42,763)	$ 54,723	$ (48,207)

ENCORE ACQUISITION COMPANY
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS Continued
(unaudited)
CONDENSED CONSOLIDATING STATEMENT OF OPERATIONS AND COMPREHENSIVE LOSS
For the Six Months Ended June 30, 2009
(in thousands)

	Parent	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Eliminations	Consolidated Total
Revenues:					
Oil	$	$ 183,051	$ 38,915	$	$ 221,966
Natural gas		46,867	7,873		54,740
Marketing		842	279		1,121
Total revenues		230,760	47,067		277,827
Expenses:					
Production:					
Lease operating		69,845	14,831		84,676
Production, ad valorem, and severance taxes		23,450	5,402		28,852
Depletion, depreciation, and amortization		122,449	22,285		144,734
Exploration		27,093	40		27,133
General and administrative	9,714	15,076	4,999	(2,316)	27,473
Marketing		1,063	191		1,254
Derivative fair value loss (gain)		(14,018)	26,533		12,515
Other operating	83	19,720	1,375		21,178
Total expenses	9,797	264,678	75,656	(2,316)	347,815
Operating loss	(9,797)	(33,918)	(28,589)	2,316	(69,988)
Other income (expenses):					
Interest	(30,522)		(4,567)		(35,089)
Equity loss from subsidiaries	(50,644)	(10,432)		61,076	
Other	(96)	3,617	6	(2,316)	1,211
Total other expenses	(81,262)	(6,815)	(4,561)	58,760	(33,878)
Loss before income taxes	(91,059)	(40,733)	(33,150)	61,076	(103,866)
Income tax benefit (provision)	36,527	117	(201)		36,443
Consolidated net loss	(54,532)	(40,616)	(33,351)	61,076	(67,423)

Change in deferred hedge loss on interest rate swaps, net of tax	(216)		648		432
Comprehensive loss	$ (54,748)	$ (40,616)	$ (32,703)	$ 61,076	$ (66,991)

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

	Parent	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Eliminations	Consolidated Total
Revenues:					
Oil	$	$ 423,122	$ 84,336	$	$ 507,458
Natural gas		97,391	18,810		116,201
Marketing		2,815	3,762		6,577
Total revenues		523,328	106,908		630,236
Expenses:					
Production:					
Lease operating		68,067	12,980		81,047
Production, ad valorem, and severance taxes		51,915	10,580		62,495
Depletion, depreciation, and amortization		82,234	18,335		100,569
Exploration		17,014	67		17,081
General and administrative	6,945	10,580	5,855	(2,134)	21,246
Marketing		3,505	4,002		7,507
Derivative fair value loss		229,513	92,015		321,528
Other operating	83	4,967	682		5,732
Total expenses	7,028	467,795	144,516	(2,134)	617,205
Operating income (loss)	(7,028)	55,533	(37,608)	2,134	13,031
Other income (expenses):					
Interest	(32,996)		(3,549)		(36,545)
Equity income (loss) from subsidiaries	31,832	(13,840)		(17,992)	
Other	(48)	3,637	82	(2,134)	1,537
Total other expenses	(1,212)	(10,203)	(3,467)	(20,126)	(35,008)
Income (loss) before income taxes	(8,240)	45,330	(41,075)	(17,992)	(21,977)
Income tax benefit (provision)	2,508	(81)	162		2,589

Consolidated net income (loss)		(5,732)		45,249		(40,913)		(17,992)		(19,388)
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		(250)				667				417
Comprehensive income (loss)	$	(7,053)	$	48,106	$	(40,246)	$	(17,992)	$	(17,185)

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ENCORE ACQUISITION COMPANY
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS Continued
(unaudited)
CONDENSED CONSOLIDATING STATEMENT OF CASH FLOWS
For the Six Months Ended June 30, 2009
(in thousands)

	Parent	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Eliminations	Consolidated Total
Cash flows from operating activities:					
Net cash provided by (used in) operating activities	$ (53,206)	$ 546,035	$ 51,318	$	$ 544,147
Cash flows from investing activities:					
Acquisition of oil and natural gas properties		(12,452)	(27,538)		(39,990)
Deposit on acquisition of oil and natural gas properties		(37,500)			(37,500)
Development of oil and natural gas properties		(231,624)	(3,477)		(235,101)
Investments in subsidiaries	242,740			(242,740)	
Other		3,231			3,231
Net cash provided by (used in) investing activities	242,740	(278,345)	(31,015)	(242,740)	(309,360)
Cash flows from financing activities:					
Proceeds from long-term debt, net of issuance costs	242,450		78,000		320,450
Payments on long-term debt	(440,000)		(33,000)		(473,000)
Proceeds from ENP issuance of common units, net of offering costs			40,724		40,724
Net equity distributions		(170,102)	(72,638)	242,740	
Other	7,453	(62,677)	(33,936)		(89,160)
Net cash used in financing activities	(190,097)	(232,779)	(20,850)	242,740	(200,986)
Increase (decrease) in cash and cash equivalents	(563)	34,911	(547)		33,801
Cash and cash equivalents, beginning of period	607	813	619		2,039

	Parent	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Eliminations	Consolidated Total
Cash and cash equivalents, end of period	$ 44	$ 35,724	$ 72	$	$ 35,840

CONDENSED CONSOLIDATING STATEMENT OF CASH FLOWS
For the Six Months Ended June 30, 2008
(in thousands)

	Parent	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Eliminations	Consolidated Total
Cash flows from operating activities:					
Net cash provided by (used in) operating activities	$ (15,147)	$ 303,826	$ 63,636	$	$ 352,315
Cash flows from investing activities:					
Acquisition of oil and natural gas properties		(49,199)	(81)		(49,280)
Development of oil and natural gas properties		(221,175)	(12,050)		(233,225)
Investments in subsidiaries	128,148			(128,148)	
Other		(23,681)	(217)		(23,898)
Net cash provided by (used in) investing activities	128,148	(294,055)	(12,348)	(128,148)	(306,403)
Cash flows from financing activities:					
Repurchase of common stock	(39,118)				(39,118)
Proceeds from long-term debt, net of issuance costs	455,029		163,310		618,339
Payments on long-term debt	(538,500)		(60,000)		(598,500)
Net equity distributions		(3,121)	(125,027)	128,148	
Other	10,000	(8,086)	(28,657)		(26,743)
Net cash used in financing activities	(112,589)	(11,207)	(50,374)	128,148	(46,022)
Increase (decrease) in cash and cash equivalents	412	(1,436)	914		(110)
Cash and cash equivalents, beginning of period	1	1,700	3		1,704
Cash and cash equivalents, end of period	$ 413	$ 264	$ 917	$	$ 1,594

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

Note 14. Commitments and Contingencies

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 condition, 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. Please read Capital Commitments, Capital Resources, and Liquidity Capital commitments Contractual obligations included in Item 2. Management s Discussion and Analysis of Financial Condition and Results of Operations of this Report for a description of EAC s contractual obligations as of June 30, 2009.

Note 15. Related Party Transactions

During the three and six months ended June 30, 2008, EAC received approximately $48.7 million and $89.3 million, respectively, from affiliates of Tesoro Corporation (Tesoro) related to gross oil and gas production sold from wells operated by Encore Operating, L.P. (Encore Operating), a Texas limited partnership and indirect wholly owned subsidiary of EAC. Mr. John V. Genova, a member of the Board, served as an employee of Tesoro until May 2008.

Please read Note 16. ENP for a discussion of related party transactions with ENP.

Note 16. ENP

Administrative Services Agreement

ENP does not have any employees. The employees supporting ENP s operations are employees of EAC. Encore Operating performs administrative services for ENP, such as accounting, corporate development, finance, land, legal, and engineering, pursuant to an administrative services agreement. In addition, Encore Operating provides all personnel, facilities, goods, and equipment necessary to perform these services which are not otherwise provided for by ENP. 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.

Encore Operating initially received an administrative fee of $1.75 per BOE of ENP s production for such services. From April 1, 2008 to March 31, 2009, the administration fee was $1.88 per BOE of ENP s production. Effective April 1, 2009, the administrative fee increased to $2.02 per BOE of ENP s production as a result of the COPAS Wage Index Adjustment. ENP also reimburses Encore Operating for actual third-party expenses incurred on ENP s behalf. 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.

The administrative fee will increase in the following circumstances:

- beginning on the first day of April in each year by an amount equal to the product of the then-current administrative fee multiplied by the COPAS Wage Index Adjustment for that year;
- if ENP or one of its subsidiaries acquires additional assets, Encore Operating may propose an increase in its administrative fee that covers the provision of services for such additional assets; however, such proposal must be approved by the board of directors of GP LLC upon the recommendation of its conflicts committee; and
- otherwise as agreed upon by Encore Operating and GP LLC, with the approval of the conflicts committee of the board of directors of GP LLC.

ENP reimburses EAC for any state income, franchise, or similar tax incurred 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 incurred had they not been included in a combined group with EAC.

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

Sales of Assets to ENP

In June 2009, Encore Operating sold certain oil and natural gas producing properties and related assets in the Williston Basin in North Dakota and Montana (the Williston Basin Assets) to ENP for approximately $25.7 million in cash, including post-closing adjustments, which was financed through borrowings under the OLLC Credit Agreement and proceeds from the issuance of ENP common units to the public. EAC used the proceeds from the sale of the properties to reduce outstanding borrowings under the EAC Credit Agreement.

In January 2009, Encore Operating sold certain oil and natural gas producing properties and related assets in the Arkoma Basin in Arkansas and royalty interest properties primarily in Oklahoma, as well as 10,300 unleased mineral acres (the Arkoma Basin Assets), to ENP for approximately $46.4 million in cash, including post-closing adjustments, which was financed through borrowings under the OLLC Credit Agreement. EAC used the proceeds from the sale of the properties to reduce outstanding borrowings under the EAC Credit Agreement.

In February 2008, Encore Operating sold certain oil and natural gas properties and related assets in the Permian Basin in West Texas and in the Williston Basin in North Dakota to ENP for approximately $125.0 million in cash, including post-closing adjustments, and 6,884,776 ENP common units. In determining the total purchase price, the common units were valued at $125.0 million. However, no accounting value was ascribed to the common units as the cash consideration exceeded Encore Operating s carrying value of the properties. The cash portion of the purchase price was financed through borrowings under the OLLC Credit Agreement. EAC used the proceeds from the sale of the properties to reduce outstanding borrowings under the EAC Credit Agreement.

Shelf Registration Statement on Form S-3

In November 2008, ENP s shelf registration statement on Form S-3 was declared effective by the SEC. Under the shelf registration statement, ENP may offer common units, senior debt, or subordinated debt in one or more offerings with a total initial offering price of up to $1 billion.

Public Offering of Common Units

In May 2009, ENP issued 2,760,000 common units under its shelf registration statement at a price to the public of $15.60 per common unit. ENP used the net proceeds of approximately $40.8 million, after deducting the underwriters discounts and commissions of $1.9 million, in the aggregate, and offering costs of approximately $0.4 million, to fund the acquisition of certain natural gas producing properties in the Vinegarone Field in Val Verde County, Texas (the Vinegarone Assets) from an independent energy company for $27.5 million, including post-closing adjustments, and a portion of the purchase price of the Williston Basin Assets.

Long-Term Incentive Plan

In September 2007, the board of directors of GP LLC adopted 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 unit-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 ENP Plan is administered by the board of directors of GP LLC or a committee thereof, referred to as the plan administrator. To satisfy common unit awards under the ENP Plan, ENP may issue common units, acquire common units in the open market, or use common units owned by EAC and its affiliates.

The total number of common units reserved for issuance pursuant to the ENP Plan is 1,150,000. As of June 30, 2009, there were 1,100,000 common units available for issuance under the ENP Plan.

Phantom Units. Each October, ENP issues 5,000 phantom units to each 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 to the grantee; therefore, these phantom units are classified as equity instruments. Phantom units vest equally over a four-year period. The holders of phantom units are also entitled to receive distribution equivalent rights prior to vesting, which entitle

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

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 each of the six months ended June 30, 2009 and 2008, ENP recognized non-cash unit-based compensation expense related to phantom units of approximately $0.2 million, which is included in General and administrative expense in the accompanying Consolidated Statements of Operations.

The following table summarizes the changes in ENP s unvested phantom units for the six months ended June 30, 2009:

	Number of Shares	Weighted Average Grant Date Fair Value
Outstanding at January 1, 2009	43,750	$18.67
Granted		
Vested		
Forfeited		
Outstanding at June 30, 2009	43,750	18.67

As of June 30, 2009, ENP had $0.4 million of total unrecognized compensation cost related to unvested phantom units, which is expected to be recognized over a weighted average period of 2.0 years.

Management Incentive Units

In May 2007, the board of directors of GP LLC issued 550,000 management incentive units to certain executive officers of GP LLC. During the fourth quarter of 2008, the management incentive units became convertible into ENP common units, at the option of the holder, at a ratio of one management incentive unit to approximately 3.1186 ENP common units, and all 550,000 management incentive units were converted into 1,715,205 ENP common units.

During the three and six months ended June 30, 2008, ENP recognized non-cash unit-based compensation expense for the management incentive units of $1.1 million and $2.1 million, respectively, which is included in General and administrative expense in the accompanying Consolidated Statements of Operations. There have been no additional issuances of management incentive units.

Distributions

During the three and six months ended June 30, 2009, ENP distributed approximately $16.8 million and $33.6 million, respectively, of which $10.7 million and $21.4 million, respectively, was paid to EAC and its subsidiaries and had no impact on EAC s consolidated cash. During the three and six months ended June 30, 2008, ENP distributed approximately $19.3 million and $29.2 million, respectively, of which $12.3 million and $18.0 million, respectively, was paid to EAC and its subsidiaries and had no impact on EAC s consolidated cash.

During the three and six months ended June 30, 2008, ENP distributed approximately $1.0 million and $1.2 million, respectively, to certain executive officers of GP LLC, who serve in the same capacities for EAC, based on their ownership of management incentive units.

Note 17. 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 is 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 2008 Annual Report on Form 10-K.

The following tables provide EAC s operating segment information required by SFAS No. 131, "*Disclosure about Segments of an Enterprise and Related Information.* The prior period financial information of ENP in the following tables was recast to include the financial results of the Arkoma Basin Assets and the Williston Basin Assets.

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

	For the Three Months Ended June 30, 2009			
	EAC Standalone	ENP	Eliminations	Consolidated Total
	(in thousands)			
Revenues:				
Oil	$ 110,495	$ 23,182	$	$ 133,677
Natural gas	25,531	3,955		29,486
Marketing	206	109		315
Total revenues	136,232	27,246		163,478
Expenses:				
Production:				
Lease operating	33,502	6,949		40,451
Production, ad valorem, and severance taxes	13,971	3,062		17,033
Depletion, depreciation, and amortization	63,140	11,294		74,434
Exploration	15,916	18		15,934
General and administrative	12,198	2,807	(1,226)	13,779
Marketing	454	61		515
Derivative fair value loss	23,666	37,440		61,106
Other operating	14,177	658		14,835
Total expenses	177,024	62,289	(1,226)	238,087
Operating loss	(40,792)	(35,043)	1,226	(74,609)
Other income (expenses):				
Interest	(16,775)	(2,351)		(19,126)
Other	1,882	1	(1,226)	657
Total other expenses	(14,893)	(2,350)	(1,226)	(18,469)
Loss before income taxes	(55,685)	(37,393)		(93,078)
Income tax benefit (provision)	31,758	(200)		31,558
Consolidated net loss	(23,927)	(37,593)		(61,520)
Change in deferred hedge loss on interest rate swaps, net of tax	(384)	1,361		977
Comprehensive loss	$ (24,311)	$ (36,232)	$	$ (60,543)

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

	For the Three Months Ended June 30, 2008			
	EAC Standalone	ENP	Eliminations	Consolidated Total
	(in thousands)			
Revenues:				
Oil	$ 235,321	$ 51,603	$	$ 286,924
Natural gas	53,235	14,654		67,889
Marketing	1,618	903		2,521
Total revenues	290,174	67,160		357,334
Expenses:				
Production:				
Lease operating	33,062	7,635		40,697
Production, ad valorem, and severance taxes	28,735	6,308		35,043
Depletion, depreciation, and amortization	40,710	10,316		51,026
Exploration	11,555	38		11,593
General and administrative	9,436	3,252	(1,129)	11,559
Marketing	2,116	1,609		3,725
Derivative fair value loss	179,962	76,428		256,390
Other operating	2,835	391		3,226
Total expenses	308,411	105,977	(1,129)	413,259
Operating loss	(18,237)	(38,817)	1,129	(55,925)
Other income (expenses):				
Interest	(14,876)	(1,909)		(16,785)
Other	1,750	65	(1,129)	686
Total other expenses	(13,126)	(1,844)	(1,129)	(16,099)
Loss before income taxes	(31,363)	(40,661)		(72,024)
Income tax benefit	21,187	135		21,322
Consolidated net loss	(10,176)	(40,526)		(50,702)
Amortization of deferred loss on commodity derivative contracts, net of tax	907			907
Change in deferred hedge gain on interest rate swaps, net of tax	(967)	2,552		1,585

Comprehensive loss	$ (10,236)	$ (37,974)	$	$ (48,210)

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

	For the Six Months Ended June 30, 2009			
	EAC Standalone	ENP	Eliminations	Consolidated Total
	(in thousands)			
Revenues:				
Oil	$ 183,051	$ 38,915	$	$ 221,966
Natural gas	46,867	7,873		54,740
Marketing	842	279		1,121
Total revenues	230,760	47,067		277,827
Expenses:				
Production:				
Lease operating	69,845	14,831		84,676
Production, ad valorem, and severance taxes	23,450	5,402		28,852
Depletion, depreciation, and amortization	122,449	22,285		144,734
Exploration	27,093	40		27,133
General and administrative	24,793	4,996	(2,316)	27,473
Marketing	1,063	191		1,254
Derivative fair value loss (gain)	(14,018)	26,533		12,515
Other operating	19,803	1,375		21,178
Total expenses	274,478	75,653	(2,316)	347,815
Operating loss	(43,718)	(28,586)	2,316	(69,988)
Other income (expenses):				
Interest	(30,522)	(4,567)		(35,089)
Other	3,521	6	(2,316)	1,211
Total other expenses	(27,001)	(4,561)	(2,316)	(33,878)
Loss before income taxes	(70,719)	(33,147)		(103,866)
Income tax benefit (provision)	36,644	(201)		36,443
Consolidated net loss	(34,075)	(33,348)		(67,423)
Change in deferred hedge loss on interest rate swaps, net of tax	(216)	648		432
Comprehensive loss	$ (34,291)	$ (32,700)	$	$ (66,991)

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

	For the Six Months Ended June 30, 2008			
	EAC Standalone	ENP	Eliminations	Consolidated Total
	(in thousands)			
Revenues:				
Oil	$ 415,014	$ 92,444	$	$ 507,458
Natural gas	92,458	23,743		116,201
Marketing	2,815	3,762		6,577
Total revenues	510,287	119,949		630,236
Expenses:				
Production:				
Lease operating	66,718	14,329		81,047
Production, ad valorem, and severance taxes	50,956	11,539		62,495
Depletion, depreciation, and amortization	80,049	20,520		100,569
Exploration	17,014	67		17,081
General and administrative	16,956	6,424	(2,134)	21,246
Marketing	3,505	4,002		7,507
Derivative fair value loss	229,513	92,015		321,528
Other operating	4,939	793		5,732
Total expenses	469,650	149,689	(2,134)	617,205
Operating income (loss)	40,637	(29,740)	2,134	13,031
Other income (expenses):				
Interest	(32,996)	(3,549)		(36,545)
Other	3,589	82	(2,134)	1,537
Total other expenses	(29,407)	(3,467)	(2,134)	(35,008)
Income (loss) before income taxes	11,230	(33,207)		(21,977)
Income tax benefit	2,451	138		2,589
Consolidated net income (loss)	13,681	(33,069)		(19,388)
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	(567)	984		417

Comprehensive income (loss)	$ 14,900	$ (32,085)	$	$ (17,185)

The following table provides EAC s balance sheet segment information as of the dates indicated:

	June 30, 2009	December 31, 2008
	(in thousands)	
Segment assets:		
EAC Standalone	$ 2,852,020	$ 3,023,571
ENP	569,299	610,792
Eliminations	(350)	(1,168)
Total consolidated assets	$ 3,420,969	$ 3,633,195
Segment liabilities:		
EAC Standalone	$ 1,730,466	$ 1,966,399
ENP	242,997	186,360
Eliminations	(2,620)	(2,812)
Total consolidated liabilities	$ 1,970,843	$ 2,149,947

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ENCORE ACQUISITION COMPANY
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS Continued
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Note 18. Subsequent Events

Subsequent events were evaluated through August 5, 2009, which is the date financial statements were issued.

Acquisitions from EXCO and Sale to ENP

On June 28, 2009, Encore Operating entered into purchase and sale agreements with EXCO Resources, Inc. (together with its affiliates, EXCO), which provides for the acquisition by Encore Operating from EXCO of certain oil and natural gas properties and related assets in the Mid-Continent and East Texas for $375 million in cash, subject to customary purchase price adjustments and closing conditions. In conjunction with the signing of the purchase and sale agreements, EAC made a $37.5 million deposit with EXCO, which is reflected as Acquisition deposit in the accompanying Consolidated Balance Sheets. The acquisitions will be effective April 1, 2009 and are expected to close in August 2009. EAC expects to finance the acquisitions through borrowings under the EAC Credit Agreement and proceeds from the sale of assets to ENP as discussed below.

Also on June 28, 2009, Encore Operating entered into a purchase and sale agreement with ENP, which provides for the sale by Encore Operating to ENP of certain oil and natural gas properties and related assets in the Big Horn Basin in Wyoming, the Permian Basin in West Texas and New Mexico, and the Williston Basin in Montana and North Dakota (the Rockies and Permian Basin Assets) for $190 million in cash, subject to customary purchase price adjustments. The sale will be effective April 1, 2009 and is expected to close in August 2009. In connection with the pending acquisition of the Rockies and Permian Basin Assets, ENP requested the syndicate of lenders underwriting the OLLC Credit Agreement to increase the borrowing base from $240 million to $375 million.

The acquisitions of properties from EXCO and the sale of properties to ENP are intended to qualify as a like-kind exchange under Section 1031 of the Internal Revenue Code of 1986, as amended, and I.R.S. Revenue Procedure 2000-37.

ENP Distribution

On July 28, 2009, ENP announced a cash distribution for the second quarter of 2009 to unitholders of record as of the close of business on August 10, 2009 at a rate of $0.5125 per unit. Approximately $23.5 million is expected to be paid to unitholders on or about August 14, 2009.

Public Offering of ENP Common Units

In July 2009, ENP issued 9,430,000 common units under its shelf registration statement at a price to the public of $14.30 per common unit. ENP expects to use the net proceeds of approximately $129.1 million, after deducting the underwriters discounts and commissions of $5.4 million, in the aggregate, and offering costs of $0.4 million, to fund a portion of the purchase price of the Rockies and Permian Basin Assets. Pending the closing of the acquisition of the Rockies and Permian Basin Assets from Encore Operating, ENP may use the net proceeds to reduce outstanding borrowings under the OLLC Credit Agreement. As a result of ENP s issuance of common units, EAC s ownership percentage of ENP s common units decreased from approximately 58 percent to approximately 46 percent.

CO2 Supply Agreement

In July 2009, EAC entered into a purchase and sale agreement to acquire a private company. This acquisition procures a CO2 supply that is expected to be used for a tertiary oil recovery project in EAC s Bell Creek Field. Under the terms of the agreement, EAC will purchase all of the volumes available from the Lost Cabin Gas Plant located in Freemont County, Wyoming. Initially, the volumes are estimated to be approximately 50 MMcf per day. The initial term of the contract is 15 years. EAC plans to build compression facilities adjacent to the plant and construct a 206-mile pipeline to transport the compressed CO2 to its Bell Creek Field in Southeastern Montana, where EAC intends to upgrade its current waterflood secondary recovery project into a miscible CO2 flood tertiary recovery project.

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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 and elsewhere in our 2008 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 2008 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:

- Second Quarter 2009 Highlights
- Results of Operations
  - Comparison of Quarter Ended June 30, 2009 to Quarter Ended June 30, 2008
  - Comparison of Six Months Ended June 30, 2009 to Six Months Ended June 30, 2008
- Capital Commitments, Capital Resources, and Liquidity
- Critical Accounting Policies and Estimates
- New Accounting Pronouncements

Second Quarter 2009 Highlights

Our financial and operating results for the second quarter of 2009 included the following:

- Our average daily production volumes increased 8 percent to 41,407 BOE/D as compared to 38,214 BOE/D in the second quarter of 2008. Oil represented 64 percent of our total production volumes as compared to 71 percent in the second quarter of 2008.
- We invested $100.4 million in oil and natural gas activities, of which $71.9 million was invested in development, exploitation, and exploration activities, yielding 24 gross (7.0 net) productive wells, and $28.3 million was invested in acquisitions, primarily related to the acquisition of the Vinegarone Assets.
- In June, we sold the Williston Basin Assets to ENP for approximately $25.7 million in cash, including post-closing adjustments. Also in June, we entered into a purchase and sale agreement with ENP, which provides for the sale of the Rockies and Permian Basin Assets to ENP for $190 million in cash, subject to customary purchase price adjustments. This transaction is expected to close in August 2009.
- In June, we entered into purchase and sale agreements with EXCO Resources, Inc., which provides for the acquisition from EXCO of certain oil and natural gas properties and related assets in the Mid-Continent and East Texas for $375 million in cash, subject to customary purchase price adjustments and closing conditions. This transaction is expected to close in August 2009.
- In May, ENP issued 2,760,000 common units under its shelf registration statement at a price to the public of $15.60 per common unit. The net proceeds of approximately $40.8 million were used to fund a portion of the purchase price of the Williston Basin Assets and the Vinegarone Assets.
- In April, we issued $225 million of our 9.5% Senior Subordinated Notes due 2016 at 92.228 percent of par value. We used the net proceeds of approximately $202.5 million to reduce outstanding borrowings under our revolving credit facility.

Subsequent to the end of the second quarter of 2009, ENP issued 9,430,000 common units under its shelf registration statement at a price to the public of $14.30 per common unit. ENP expects to use the net proceeds of approximately $129.1 million to fund a portion of the purchase price of the Rockies and Permian Basin Assets.

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Results of Operations

Comparison of Quarter Ended June 30, 2009 to Quarter Ended June 30, 2008

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

	Three months ended June 30,		Increase / (Decrease)	
	2009	2008	$	%
Revenues (in thousands):				
Oil wellhead	$ 133,677	$ 288,352	*$ (154,675)*	
Oil hedges		(1,428)	*1,428*	
Total oil revenues	$ 133,677	$ 286,924	*$ (153,247)*	*-53%*
Natural gas wellhead	$ 29,486	$ 67,889	*$ (38,403)*	*-57%*
Combined wellhead	$ 163,163	$ 356,241	*$ (193,078)*	
Combined hedges		(1,428)	*1,428*	
Total combined oil and natural gas revenues	163,163	354,813	*(191,650)*	*-54%*
Marketing	315	2,521	*(2,206)*	*-88%*
Total revenues	$ 163,478	$ 357,334	*$ (193,856)*	*-54%*
Average realized prices:				
Oil wellhead ($/Bbl)	$ 55.02	$ 117.22	*$ (62.20)*	
Oil hedges ($/Bbl)		(0.58)	*0.58*	
Total oil revenues ($/Bbl)	$ 55.02	$ 116.64	*$ (61.62)*	*-53%*
Natural gas wellhead ($/Mcf)	$ 3.67	$ 11.12	*$ (7.45)*	*-67%*
Combined wellhead ($/BOE)	$ 43.30	$ 102.44	*$ (59.14)*	
Combined hedges ($/BOE)		(0.41)	*0.41*	
Total combined oil and natural gas revenues ($/BOE)	$ 43.30	$ 102.03	*$ (58.73)*	*-58%*
Total production volumes:				
Oil (MBbls)	2,430	2,460	*(30)*	*-1%*
Natural gas (MMcf)	8,030	6,105	*1,925*	*32%*
Combined (MBOE)	3,768	3,477	*291*	*8%*
Average daily production volumes:				
Oil (Bbls/D)	26,701	27,032	*(331)*	*-1%*
Natural gas (Mcf/D)	88,236	67,090	*21,146*	*32%*
Combined (BOE/D)	41,407	38,214	*3,193*	*8%*

Average NYMEX prices:							
Oil (per Bbl)	$	59.83	$	124.30	*$*	*(64.47)*	*-52%*
Natural gas (per Mcf)	$	3.49	$	10.94	*$*	*(7.45)*	*-68%*

Oil revenues decreased 53 percent from $286.9 million in the second quarter of 2008 to $133.7 million in the second quarter of 2009 as a result of a $61.62 per Bbl decrease in our average realized oil price and a 30 MBbls decrease in our oil production volumes. Our lower oil production volumes decreased oil revenues by approximately $3.5 million and was primarily due to natural production declines in our Elk Basin field.

Our average realized oil price decreased primarily due to our lower average oil wellhead price, which decreased oil revenues by approximately $151.1 million, or $62.20 per Bbl. Our average oil wellhead price decreased primarily due to a lower average NYMEX price, which decreased from $124.30 per Bbl in the second quarter of 2008 to $59.83 Bbl in the second quarter of 2009. Oil revenues in the second quarter of 2008 were also reduced by approximately $1.4 million, or $0.58 per Bbl, for commodity derivative contracts previously designated as hedges.

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In the second quarter of 2009 and 2008, our average daily production volumes were decreased by 2,065 BOE/D and 1,943 BOE/D, respectively, for net profits interests related to our CCA properties, which reduced our oil wellhead revenues by approximately $8.6 million and $18.3 million, respectively.

Natural gas revenues decreased 57 percent from $67.9 million in the second quarter of 2008 to $29.5 million in the second quarter of 2009 as a result of a $7.45 per Mcf decrease in our average realized natural gas price, partially offset by a 1,925 MMcf increase in our natural gas production volumes. Our lower average realized natural gas price decreased natural gas revenues by approximately $59.8 million and was primarily due to a lower average NYMEX price, which decreased from $10.94 per Mcf in the second quarter of 2008 to $3.49 per Mcf in the second quarter of 2009. Our higher natural gas production increased natural gas revenues by approximately $21.4 million and was primarily due to successful development programs in our Permian Basin and Mid-Continent areas.

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

	Three months ended June 30,	
	2009	2008
Average oil wellhead ($/Bbl)	$55.02	$117.22
Average NYMEX ($/Bbl)	$59.83	$124.30
Differential to NYMEX	$ (4.81)	$ (7.08)
Average oil wellhead to NYMEX percentage	92%	94%
Average natural gas wellhead ($/Mcf)	$ 3.67	$ 11.12
Average NYMEX ($/Mcf)	$ 3.49	$ 10.94
Differential to NYMEX	$ 0.18	$ 0.18
Average natural gas wellhead to NYMEX percentage	105%	102%

Our average oil wellhead price as a percentage of the average NYMEX price was 92 percent in the second quarter of 2009 as compared to 94 percent in the second quarter of 2008.

Our average natural gas wellhead price as a percentage of the average NYMEX price was 105 percent in the second quarter of 2009 as compared to 102 percent in the second quarter of 2008. 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. Additionally in the second quarter of 2009, we recorded a one-time positive $1.0 million value price adjustment for NGLs marketed by a third party. As a result, the price we were paid per Mcf for natural gas sold under certain contracts during the second quarter of 2009 increased to a level above NYMEX.

Marketing revenues decreased 88 percent from $2.5 million in the second quarter of 2008 to $0.3 million in the second quarter of 2009 primarily as a result of a reduction in natural gas throughput in our Wildhorse pipeline. Natural gas volumes are purchased from numerous gas producers at the inlet of the pipeline and resold downstream to various local and off-system markets.

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Expenses. The following table summarizes our expenses for the periods indicated:

	Three months ended June 30,		Increase / (Decrease)	
	2009	2008	$	%
Expenses (in thousands):				
Production:				
Lease operating	$ 40,451	$ 40,697	$ (246)	
Production, ad valorem, and severance taxes	17,033	35,043	(18,010)	
Total production expenses	57,484	75,740	(18,256)	-24%
Other:				
Depletion, depreciation, and amortization	74,434	51,026	23,408	
Exploration	15,934	11,593	4,341	
General and administrative	13,779	11,559	2,220	
Marketing	515	3,725	(3,210)	
Derivative fair value loss	61,106	256,390	(195,284)	
Other operating	14,835	3,226	11,609	
Total operating expenses	238,087	413,259	(175,172)	-42%
Interest	19,126	16,785	2,341	
Income tax benefit	(31,558)	(21,322)	(10,236)	
Total expenses	$ 225,655	$ 408,722	$ (183,067)	-45%
Expenses (per BOE):				
Production:				
Lease operating	$ 10.74	$ 11.70	$ (0.96)	
Production, ad valorem, and severance taxes	4.52	10.08	(5.56)	
Total production expenses	15.26	21.78	(6.52)	-30%
Other:				
Depletion, depreciation, and amortization	19.75	14.67	5.08	
Exploration	4.23	3.33	0.90	
General and administrative	3.66	3.32	0.34	
Marketing	0.14	1.07	(0.93)	
Derivative fair value loss	16.22	73.73	(57.51)	
Other operating	3.94	0.93	3.01	
Total operating expenses	63.20	118.83	(55.63)	-47%
Interest	5.08	4.83	0.25	
Income tax benefit	(8.38)	(6.13)	(2.25)	
Total expenses	$ 59.90	$ 117.53	$ (57.63)	-49%

Production expenses. Total production expenses decreased 24 percent from $75.7 million in the second quarter of 2008 to $57.5 million in the second quarter of 2009. Our production margin decreased 62 percent from $280.5 million in the second quarter of 2008 to $105.7 million in the second quarter of 2009. Total oil and natural gas wellhead revenues per BOE decreased by 58 percent and total production expenses per BOE decreased by 30 percent. On a per BOE basis, our production margin decreased 65 percent to $28.04 per BOE in the second quarter of 2009 as compared to $80.66 per BOE in the second quarter of 2008.

Production expense attributable to LOE remained flat at $40.5 million in the second quarter of 2009 as compared to $40.7 million in the second quarter of 2008. Our higher production volumes increased LOE by approximately $3.4 million. The $0.96 decrease in our average LOE per BOE rate decreased LOE by approximately $3.6 million and was primarily due to decreases in natural gas prices resulting in lower electricity costs and gas plant fuel costs, as well as lower prices paid to oilfield service companies and suppliers, partially offset by an increase of $3.2 million for retention bonuses to be paid in August 2009 related to our 2008 strategic alternatives process.

Production expense attributable to production, ad valorem, and severance taxes (production taxes) decreased $18.0 million from $35.0 million in the second quarter of 2008 to $17.0 million in the second quarter of 2009 primarily due to lower wellhead revenues, which exclude the effects of commodity derivative contracts. As a percentage of oil and natural gas wellhead revenues, production taxes increased to 10.4 percent in the second quarter of 2009 as compared to 9.8 percent in the second quarter of 2008 primarily due to higher ad valorem taxes, which are based on a flat rate of production volumes as opposed to a percentage of wellhead revenues.

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Depletion, depreciation, and amortization expense (DD&A). DD&A expense increased $23.4 million from $51.0 million in the second quarter of 2008 to $74.4 million in the second quarter of 2009 as a result of a $5.08 increase in the per BOE rate and higher production volumes. Our higher average DD&A per BOE rate increased DD&A expense by approximately $19.1 million and was primarily due to the decrease in our proved reserves as a result of lower average commodity prices. Our higher production volumes increased DD&A expense by approximately $4.3 million.

Exploration expense. Exploration expense increased $4.3 million from $11.6 million in the second quarter of 2008 to $15.9 million in the second quarter of 2009. During the second quarter of 2009, we expensed 2.9 net exploratory dry holes totaling $9.5 million. During the second quarter of 2008, we expensed 2.0 net exploratory dry holes totaling $6.6 million. Impairment of unproved acreage increased $1.6 million from $4.2 million in the second quarter of 2008 to $5.8 million in the second quarter of 2009, primarily due to our larger unproved property base, as well as the impairment of certain acreage through the normal course of evaluation. The following table illustrates the components of exploration expense for the periods indicated:

	Three months ended June 30, 2009	2008	*Increase / (Decrease)*
		(in thousands)	
Dry holes	$ 9,467	$ 6,612	*$ 2,855*
Geological and seismic	525	455	*70*
Delay rentals	136	357	*(221)*
Impairment of unproved acreage	5,806	4,169	*1,637*
Total	$ 15,934	$ 11,593	*$ 4,341*

General and administrative expense (G&A). G&A expense increased $2.2 million from $11.6 million in the second quarter of 2008 to $13.8 million in the second quarter of 2009 primarily due to an increase of $1.4 million for retention bonuses to be paid in August 2009 related to our 2008 strategic alternatives process and the expensing of transaction costs related to our 2009 acquisitions pursuant to SFAS 141R.

Marketing expenses. Marketing expenses decreased $3.2 million from $3.7 million in the second quarter of 2008 to $0.5 million in the second quarter of 2009 primarily due to a reduction in natural gas throughput in our Wildhorse pipeline. Natural gas volumes are purchased from numerous gas producers at the inlet of the pipeline and resold downstream to various local and off-system markets.

Derivative fair value loss. During the second quarter of 2009, we recorded a $61.1 million derivative fair value loss as compared to $256.4 million in the second quarter of 2008, the components of which were as follows:

	Three months ended June 30, 2009	2008	*Decrease*
		(in thousands)	
Ineffectiveness	$ 6	$ 39	*$ (33)*
Mark-to-market loss	78,082	219,433	*(141,351)*
Premium amortization	6,764	17,293	*(10,529)*
Settlements	(23,746)	19,625	*(43,371)*
Total derivative fair value loss	$ 61,106	$ 256,390	*$ (195,284)*

Other operating expense. Other operating expense increased $11.6 million from $3.2 million in the second quarter of 2008 to $14.8 million in the second quarter of 2009. Other operating expense for the second quarter of 2009 includes a $5.6 million adjustment to the carrying value of pipe and other tubular inventory whose market value had declined below cost and a $4.7 million adjustment to the carrying value of certain receivables, primarily from ExxonMobil related to our West Texas joint venture.

Interest expense. Interest expense increased $2.3 million from $16.8 million in the second quarter of 2008 to $19.1 million in the second quarter of 2009 primarily due to the issuance of $225 million of our 9.50% Notes, partially offset by a reduction in LIBOR. We received net proceeds of approximately $202.5 million from the issuance of the 9.5% Notes, which we used to reduce outstanding borrowings under our revolving credit facility. Our weighted average interest rate was 6.1 percent for the second quarter of 2009 as compared to 5.4 percent for the second quarter of 2008.

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

	Three months ended June 30, 2009	Three months ended June 30, 2008	*Increase / (Decrease)*
	(in thousands)		
6.25% Senior Subordinated Notes	$ 2,436	$ 2,431	*$ 5*
6.0% Senior Subordinated Notes	4,644	4,636	*8*
9.5% Senior Subordinated Notes	4,169		*4,169*
7.25% Senior Subordinated Notes	2,751	2,749	*2*
Revolving credit facilities	3,966	7,215	*(3,249)*
Other	1,160	(246)	*1,406*
Total	$ 19,126	$ 16,785	*$ 2,341*

Income taxes. In the second quarter of 2009, we recorded an income tax benefit of $31.6 million as compared to $21.3 million in the second quarter of 2008. In the second quarter of 2009, we had a loss before income taxes and noncontrolling interest of $93.1 million as compared to $72.0 million in the second quarter of 2008. Our effective tax rate increased to 33.9 percent in the second quarter of 2009 as compared to 29.6 percent in the second quarter of 2008 primarily due to a permanent increase in the production activities deduction.

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Comparison of Six Months Ended June 30, 2009 to Six Months Ended June 30, 2008

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

	Six months ended June 30, 2009	Six months ended June 30, 2008	*Increase / (Decrease) $*	*%*
Revenues (in thousands):				
Oil wellhead	$ 221,966	$ 510,315	*$ (288,349)*	
Oil hedges		(2,857)	*2,857*	
Total oil revenues	$ 221,966	$ 507,458	*$ (285,492)*	*-56%*
Natural gas wellhead	$ 54,740	$ 116,201	*$ (61,461)*	*-53%*
Combined wellhead	$ 276,706	$ 626,516	*$ (349,810)*	
Combined hedges		(2,857)	*2,857*	
Total combined oil and natural gas revenues	276,706	623,659	*(346,953)*	*-56%*
Marketing	1,121	6,577	*(5,456)*	*-83%*
Total revenues	$ 277,827	$ 630,236	*$ (352,409)*	*-56%*
Average realized prices:				
Oil wellhead ($/Bbl)	$ 45.14	$ 102.81	*$ (57.67)*	
Oil hedges ($/Bbl)		(0.58)	*0.58*	
Total oil revenues ($/Bbl)	$ 45.14	$ 102.23	*$ (57.09)*	*-56%*
Natural gas wellhead ($/Mcf)	$ 3.48	$ 9.73	*$ (6.25)*	*-64%*
Combined wellhead ($/BOE)	$ 36.70	$ 90.10	*$ (53.40)*	
Combined hedges ($/BOE)		(0.41)	*0.41*	
Total combined oil and natural gas revenues ($/BOE)	$ 36.70	$ 89.69	*$ (52.99)*	*-59%*
Total production volumes:				
Oil (MBbls)	4,918	4,964	*(46)*	*-1%*
Natural gas (MMcf)	15,727	11,937	*3,790*	*32%*
Combined (MBOE)	7,539	6,953	*586*	*8%*

Average daily production volumes:				
Oil (Bbls/D)	27,170	27,274	*(104)*	*0%*
Natural gas (Mcf/D)	86,890	65,586	*21,304*	*32%*
Combined (BOE/D)	41,652	38,205	*3,447*	*9%*
Average NYMEX prices:				
Oil (per Bbl)	$ 51.61	$ 111.02	*$ (59.41)*	*-54%*
Natural gas (per Mcf)	$ 4.20	$ 9.48	*$ (5.28)*	*-56%*

Oil revenues decreased 56 percent from $507.5 million in the first six months of 2008 to $222.0 million in the first six months of 2009 as a result of a $57.09 per Bbl decrease in our average realized oil price and a 46 MBbls decrease in our oil production volumes. Our lower oil production volumes decreased oil revenues by approximately $4.7 million and was primarily due to natural production declines in our Elk Basin field.

Our average realized oil price decreased primarily due to our lower average oil wellhead price, which decreased oil revenues by approximately $283.6 million, or $57.67 per Bbl. Our average oil wellhead price decreased primarily due to a lower average NYMEX price, which decreased from $111.02 per Bbl in the first six months of 2008 to $51.61 Bbl in the first six months of 2009. Oil revenues in the first six months of 2008 were also reduced by approximately $2.9 million, or $0.58 per Bbl, for commodity derivative contracts previously designated as hedges.

In the first six months of 2009 and 2008, our average daily production volumes were decreased by 1,738 BOE/D and 1,883 BOE/D, respectively, for net profits interests related to our CCA properties, which reduced our oil wellhead revenues by approximately $12.4 million and $31.2 million, respectively.

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Natural gas revenues decreased 53 percent from $116.2 million in the first six months of 2008 to $54.7 million in the first six months of 2009 as a result of a $6.25 per Mcf decrease in our average realized natural gas price, partially offset by a 3,790 MMcf increase in our natural gas production volumes. Our lower average realized natural gas price decreased natural gas revenues by approximately $98.4 million and was primarily due to a lower average NYMEX price, which decreased from $9.48 per Mcf in the first six months of 2008 to $4.20 per Mcf in the first six months of 2009. Our higher natural gas production increased natural gas revenues by approximately $36.9 million and was primarily due to successful development programs in our Permian Basin and Mid-Continent areas.

The table below illustrates the relationship between our oil and natural gas wellhead prices as a percentage of average NYMEX prices for the periods indicated:

	Six months ended June 30,	
	2009	2008
Average oil wellhead ($/Bbl)	$45.14	$102.81
Average NYMEX ($/Bbl)	$51.61	$111.02
Differential to NYMEX	$ (6.47)	$ (8.21)
Average oil wellhead to NYMEX percentage	87%	93%
Average natural gas wellhead ($/Mcf)	$ 3.48	$ 9.73
Average NYMEX ($/Mcf)	$ 4.20	$ 9.48
Differential to NYMEX	$ (0.72)	$ 0.25
Average natural gas wellhead to NYMEX percentage	83%	103%

Our average oil wellhead price as a percentage of the average NYMEX price was 87 percent in the first six months of 2009 as compared to 93 percent in the first six months of 2008. The percentage differential widened as a result of a 54 percent decrease in NYMEX as compared to the first six months of 2008. However, the per Bbl differential improved from $8.21 per Bbl in the first six months of 2008 to $6.47 per Bbl in the first six months of 2009.

Our average natural gas wellhead price as a percentage of the average NYMEX price was 83 percent in the first six months of 2009 as compared to 103 percent in the first six months of 2008. 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 first six months of 2008, the price of NGLs increased at a much faster pace than did the price of natural gas resulting in a price we were paid per Mcf under certain contracts to be higher than the NYMEX. During the first half of 2009, we recorded a one-time positive $1.0 million value price adjustment for NGLs marketed by a third party. However, the natural gas index prices related to our West Texas, Permian, East Texas, and Rocky Mountains natural gas contracts all widened in their relationship to NYMEX causing an overall wider differential for the first six months of 2009.

Marketing revenues decreased 83 percent from $6.6 million in the first six months of 2008 to $1.1 million in the first six months of 2009 primarily as a result of a reduction in natural gas throughput in our Wildhorse pipeline. Natural gas volumes are purchased from numerous gas producers at the inlet of the pipeline and resold downstream to various local and off-system markets.

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Expenses. The following table summarizes our expenses for the periods indicated:

	Six months ended June 30,		Increase / (Decrease)	
	2009	2008	$	%
Expenses (in thousands):				
Production:				
Lease operating	$ 84,676	$ 81,047	*$ 3,629*	
Production, ad valorem, and severance taxes	28,852	62,495	*(33,643)*	
Total production expenses	113,528	143,542	*(30,014)*	*-21%*
Other:				
Depletion, depreciation, and amortization	144,734	100,569	*44,165*	
Exploration	27,133	17,081	*10,052*	
General and administrative	27,473	21,246	*6,227*	
Marketing	1,254	7,507	*(6,253)*	
Derivative fair value loss	12,515	321,528	*(309,013)*	
Other operating	21,178	5,732	*15,446*	
Total operating expenses	347,815	617,205	*(269,390)*	*-44%*
Interest	35,089	36,545	*(1,456)*	
Income tax benefit	(36,443)	(2,589)	*(33,854)*	
Total expenses	$ 346,461	$ 651,161	*$ (304,700)*	*-47%*
Expenses (per BOE):				
Production:				
Lease operating	$ 11.23	$ 11.66	*$ (0.43)*	
Production, ad valorem, and severance taxes	3.83	8.99	*(5.16)*	
Total production expenses	15.06	20.65	*(5.59)*	*-27%*
Other:				
Depletion, depreciation, and amortization	19.20	14.46	*4.74*	
Exploration	3.60	2.46	*1.14*	
General and administrative	3.64	3.06	*0.58*	
Marketing	0.17	1.08	*(0.91)*	
Derivative fair value loss	1.66	46.24	*(44.58)*	
Other operating	2.81	0.82	*1.99*	
Total operating expenses	46.14	88.77	*(42.63)*	*-48%*
Interest	4.65	5.26	*(0.61)*	
Income tax benefit	(4.83)	(0.37)	*(4.46)*	
Total expenses	$ 45.96	$ 93.66	*$ (47.70)*	*-51%*

Production expenses. Total production expenses decreased 21 percent from $143.5 million in the first six months of 2008 to $113.5 million in the first six months of 2009. Our production margin decreased 66 percent from

$483.0 million in the first six months of 2008 to $163.2 million in the first six months of 2009. Total oil and natural gas wellhead revenues per BOE decreased by 59 percent and total production expenses per BOE decreased by 27 percent. On a per BOE basis, our production margin decreased 69 percent to $21.64 per BOE in the first six months of 2009 as compared to $69.45 per BOE in the first six months of 2008.

Production expense attributable to LOE increased $3.6 million from $81.0 million in the first six months of 2008 to $84.7 million in the first six months of 2009 as a result of higher production volumes, partially offset by a $0.43 decrease in the per BOE rate. Our higher production volumes increased LOE by approximately $6.8 million. Our lower average LOE per BOE rate decreased LOE by approximately $3.2 million and was primarily due to decreases in natural gas prices resulting in lower electricity costs and gas plant fuel costs, as well as lower prices paid to oilfield service companies and suppliers, partially offset by an increase of $7.0 million for retention bonuses to be paid in August 2009 related to our 2008 strategic alternatives process.

Production expense attributable to production taxes decreased $33.6 million from $62.5 million in the first six months of 2008 to $28.9 million in the first six months of 2009 primarily due to lower wellhead revenues, which exclude the effects of commodity derivative contracts. As a percentage of oil and natural gas wellhead revenues, production taxes increased to 10.4 percent in the first six months of 2009 as compared to 10.0 percent in the first six months of 2008 primarily due to higher ad valorem taxes, which are based on a flat rate of production volumes as opposed to a percentage of wellhead revenues.

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DD&A expense. DD&A expense increased $44.2 million from $100.6 million in the first six months of 2008 to $144.7 million in the first six months of 2009 as a result of a $4.74 increase in the per BOE rate and higher production volumes. Our higher average DD&A per BOE rate increased DD&A expense by approximately $35.7 million and was primarily due to the decrease in our proved reserves as a result of lower average commodity prices. Our higher production volumes increased DD&A expense by approximately $8.5 million.

Exploration expense. Exploration expense increased $10.1 million from $17.1 million in the first six months of 2008 to $27.1 million in the first six months of 2009. During the first six months of 2009, we expensed 3.9 net exploratory dry holes totaling $14.5 million. During the first six months of 2008, we expensed 2.5 net exploratory dry holes totaling $7.2 million. Impairment of unproved acreage increased $3.5 million from $8.3 million in the first six months of 2008 to $11.8 million in the first six months of 2009, primarily due to our larger unproved property base, as well as the impairment of certain acreage through the normal course of evaluation. The following table illustrates the components of exploration expense for the periods indicated:

	Six months ended June 30, 2009	Six months ended June 30, 2008	*Increase / (Decrease)*
	(in thousands)		
Dry holes	$ 14,513	$ 7,234	*$ 7,279*
Geological and seismic	639	833	*(194)*
Delay rentals	230	703	*(473)*
Impairment of unproved acreage	11,751	8,311	*3,440*
Total	$ 27,133	$ 17,081	*$ 10,052*

G&A expense. G&A expense increased $6.2 million from $21.2 million in the first six months of 2008 to $27.5 million in the first six months of 2009 primarily due to an increase of $3.0 million for retention bonuses to be paid in August 2009 related to our 2008 strategic alternatives process and the expensing of transaction costs related to our 2009 acquisitions pursuant to SFAS 141R.

Marketing expenses. Marketing expenses decreased $6.3 million from $7.5 million in the first six months of 2008 to $1.3 million in the first six months of 2009 primarily due to a reduction in natural gas throughput in our Wildhorse pipeline. Natural gas volumes are purchased from numerous gas producers at the inlet of the pipeline and resold downstream to various local and off-system markets.

Derivative fair value loss. During the first six months of 2009, we recorded a $12.5 million derivative fair value loss as compared to $321.5 million in the first six months of 2008, the components of which were as follows:

	Six Months Ended June 30, 2009	Six Months Ended June 30, 2008	*Increase / (Decrease)*
	(in thousands)		
Ineffectiveness	$ (34)	$ (343)	*$ 309*
Mark-to-market loss	280,993	265,048	*15,945*
Premium amortization	84,719	32,806	*51,913*
Settlements	(353,163)	24,017	*(377,180)*
Total derivative fair value loss	$ 12,515	$ 321,528	*$ (309,013)*

Other operating expense. Other operating expense increased $15.4 million from $5.7 million in the first six months of 2008 to $21.2 million in the first six months of 2009. Other operating expense for the first six months of

2009 includes a $5.7 million adjustment to the carrying value of pipe and other tubular inventory whose market value had declined below cost and a $4.7 million adjustment to the carrying value of certain receivables, primarily from ExxonMobil related to our West Texas joint venture.

Interest expense. Interest expense decreased $1.5 million from $36.5 million in the first six months of 2008 to $35.1 million in the first six months of 2009 primarily due to a reduction in LIBOR, partially offset by the issuance of our 9.5% Notes. Our weighted average interest rate was 5.0 percent for the first six months of 2009 as compared to 5.9 percent for the first six months of 2008.

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

	Six months ended June 30, 2009	Six months ended June 30, 2008	*Increase / (Decrease)*
	(in thousands)		
6.25% Senior Subordinated Notes	$ 4,872	$ 4,861	*$ 11*
6.0% Senior Subordinated Notes	9,288	9,271	*17*
9.5% Senior Subordinated Notes	4,169		*4,169*
7.25% Senior Subordinated Notes	5,501	5,497	*4*
Revolving credit facilities	8,687	15,605	*(6,918)*
Other	2,572	1,311	*1,261*
Total	$ 35,089	$ 36,545	*$ (1,456)*

Income taxes. In the first six months of 2009, we recorded an income tax benefit of $36.4 million as compared to $2.6 million in the first six months of 2008. In the first six months of 2009, we had a loss before income taxes and noncontrolling interest of $103.9 million as compared to $22.0 million in the first six months of 2008. Our effective tax rate increased to 35.1 percent in the first six months of 2009 as compared to 11.8 percent in the first six months of 2008 primarily due to the permanent adjustment for ENP s pre-tax loss remaining flat while EAC s consolidated pre-tax loss increased $81.9 million, or 373 percent.

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 working capital; and
- Contractual obligations.

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 June 30, 2009	Three months ended June 30, 2008	Six months ended June 30, 2009	Six months ended June 30, 2008
	(in thousands)			
Development and exploitation	$ 24,993	$ 76,876	$ 75,340	$ 134,248
Exploration	46,930	65,431	117,016	109,257
Total	$ 71,923	$ 142,307	$ 192,356	$ 243,505

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 second quarter of 2009 yielded 14 gross (4.7 net) successful wells and no dry holes. Our development and exploitation capital for the first six months of 2009 yielded 48 gross (13.6 net) successful wells and no 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 second quarter of 2009 yielded 10 gross (2.3 net) successful wells and 3 gross (2.9 net) dry holes. Our exploration capital for the first six months of 2009 yielded 33 gross (9.8 net) successful wells and 4 gross (3.9 net) dry holes.

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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 June 30,		Six months ended June 30,	
	2009	2008	2009	2008
	(in thousands)			
Acquisitions of proved property	$ 27,470	$ 5,687	$ 27,552	$ 20,468
Acquisitions of leasehold acreage	874	18,642	4,176	34,641
Total	$ 28,344	$ 24,329	$ 31,728	$ 55,109

In May 2009, ENP acquired the Vinegarone Assets for approximately $27.5 million in cash, including post-closing adjustments. Our capital expenditures for leasehold acreage relate to the acquisition of unproved acreage in various areas.

Funding of working capital. As of June 30, 2009 and December 31, 2008, our working capital (defined as total current assets less total current liabilities) was a negative $53.0 million and a positive $188.7 million, respectively. The decrease was primarily due to the monetization of certain of our 2009 oil derivative contracts in March 2009 and higher commodity prices at June 30, 2009 as compared to December 31, 2008, which negatively impacted the fair value of our outstanding commodity derivative contracts.

For the remainder of 2009, we expect working capital to remain negative, primarily due to lower commodity prices. 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 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. Our operating cash flow is determined in large part by production volumes and commodity prices. Given our current commodity derivative contracts, assuming relatively stable commodity prices and constant or increasing production volumes, our operating cash flow should remain positive for the remainder of 2009.

The Board approved a revised capital budget of $340 million for 2009, excluding proved property acquisitions, which is a $30 million increase from our previously approved capital budget for 2009. The level of these and other future expenditures are 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 availability 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 June 30, 2009:

			Payments Due by Period			
Contractual Obligations and Commitments	**Maturity Date**	**Total**	**Six Months Ending December 31, 2009**	**Years Ending December 31,**	**Years Ending December 31,**	**Thereafter**

				2010 - 2011	2012 - 2013	
				(in thousands)		
6.25% Senior Subordinated Notes (a)	4/15/2014	$ 196,875	$ 4,687	$ 18,750	$ 18,750	$ 154,688
6.0% Senior Subordinated Notes (a)	7/15/2015	417,000	9,000	36,000	36,000	336,000
9.5% Senior Subordinated Notes (a)	5/1/2016	374,625	10,687	42,750	42,750	278,438
7.25% Senior Subordinated Notes (a)	12/1/2017	242,438	5,438	21,750	21,750	193,500
Revolving credit facilities (a)	3/7/2012	395,778	4,687	18,748	372,343	
Commodity derivative contracts (b)		43,817		20,066	16,500	7,251
Interest rate swaps (c)		3,925	1,772	2,153		
Capital lease obligations		1,514	233	932	349	
Development commitments (d)		58,281	30,429	27,852		
Operating leases and commitments (e)		15,497	1,956	7,577	5,964	
Asset retirement obligations (f)		179,854	1,668	3,336	2,502	172,348
Total		$ 1,929,604	$ 70,557	$ 199,914	$ 516,908	$ 1,142,225

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(a) Includes principal and projected interest payments. Please read Note 7 of Notes to Consolidated Financial Statements included in Item 1. Financial Statements for additional information regarding our long-term debt.

(b) Represents net liabilities for commodity derivative contracts. With the exception of $38.9 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 Note 5 of Notes to Consolidated Financial Statements included in Item 1. Financial Statements for additional information regarding our commodity derivative contracts.

(c) Represents net liabilities for interest rate swaps, the ultimate settlement of which are unknown because they are subject to continuing market risk. Please read Item 3. Quantitative and Qualitative Disclosures about Market Risk and Note 5 of Notes to Consolidated Financial Statements included in Item 1. Financial Statements for additional information regarding our interest rate swaps.

(d)

Includes authorized purchases for work in process of $55.7 million and future minimum payments for drilling rig operations of $2.6 million. Also at June 30, 2009, we had approximately $149.7 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.

(e) Includes office space and equipment obligations that have non-cancelable initial lease terms in excess of one year of $15.0 million and future minimum payments for other operating commitments of $0.5 million.

(f) Represents 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 6 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. 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 oversubscribed and subject to apportionment, we have been allocated sufficient pipeline capacity to move our crude oil production. An expansion of the Enbridge Pipeline was completed in early 2008, which moved the total Rockies area pipeline takeaway closer to a balancing point with increasing production volumes and thereby provided greater stability to oil differentials in the area. In spite of the increase in capacity, the Enbridge Pipeline continues to run at full 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, 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.

The difference between NYMEX market prices and the price received at the wellhead for oil and natural gas production is commonly referred to as a differential. 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. We cannot accurately predict future oil and natural gas differentials. Increases in the percentage 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 $191.8 million from $352.3 million for the first six months of 2008 to $544.1 million for the first six months of 2009, primarily due to the monetization of certain of our 2009 oil derivative contracts in March 2009 and decreased settlements paid under our commodity derivative contracts as a result of lower average commodity prices in the first six months of 2009 as compared to the first six months of 2008, partially offset by a decrease in our production margin.

Cash flows from investing activities. Cash used in investing activities increased $3.0 million from $306.4 million in the first six months of 2008 to $309.4 million in the first six months of 2009, primarily due to a $28.2 million increase in amounts paid to acquire oil and natural gas properties, partially offset by a $26.6 million decrease in net advancements to working interest partners. During the first six months of 2009, we collected $3.7 million (net of advancements) from ExxonMobil for their portion of costs incurred drilling wells under the joint development agreement. During the first six months of 2008, we advanced $22.9 million (net of collections) to ExxonMobil for their portion of costs incurred drilling wells under the joint development agreement.

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

During the first six months of 2009, we used net cash of $201.0 million in financing activities, including net repayments on revolving credit facilities of $355 million, payments for deferred commodity derivative contract premiums of $69.5 million, and ENP distributions to noncontrolling interests of $12.2 million, partially offset by $202.5 million of net proceeds from the issuance of the 9.5% Notes and $40.7 million of net proceeds from ENP issuance of common units. Net repayments decreased the outstanding borrowings under revolving credit facilities from $725 million at December 31, 2008 to $370 million at June 30, 2009.

In October 2008, we announced that the Board approved a share repurchase program authorizing us to repurchase 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 June 30, 2009, 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 share repurchase program. During the first six months of 2009, we did not repurchase any shares of our outstanding common stock under the share repurchase program. As of June 30, 2009, approximately $22.8 million of our common stock remained authorized for repurchase.

During the first six months of 2008, we used net cash of $46.0 million in financing activities, including net borrowings on revolving credit facilities of $21 million, partially offset by $39.1 million of share repurchases, payments for deferred commodity derivative contract premiums of $20.6 million, and ENP distributions to noncontrolling interests of $11.2 million.

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 the level of our capital expenditures. We may use other sources of capital, including the issuance of 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. However, should commodity prices decline or the capital markets remain tight, the borrowing capacity under our revolving credit facilities could be adversely affected. In the event of a reduction in the borrowing base under our revolving credit facilities, we do not believe it will result in any required prepayments of indebtedness.

We plan to make substantial capital expenditures in the future for the acquisition, exploitation, and development of oil and natural gas properties. We intend to finance these capital expenditures with cash flows from operations. We intend to finance our acquisition and future development and exploitation activities with a combination of cash flows from operations and issuances of debt, equity, or a combination thereof.

Issuance of 9.5% Senior Subordinated Notes Due 2016. On April 27, 2009, we issued $225 million of our 9.5% Notes at 92.228 percent of par value. We used the net proceeds of approximately $202.5 million to reduce outstanding borrowings under our revolving credit facility. Interest on the 9.5% Notes is due semi-annually on May 1 and November 1, beginning November 1, 2009. The 9.5% Notes mature on May 1, 2016.

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 six months of 2009, our average realized oil and natural gas prices decreased by 56 percent and 64 percent, respectively, as compared to the first six months of 2008. Realized oil and natural gas prices fluctuate widely in response to changing market forces. If oil and natural gas prices decline or we experience a significant widening of our differentials, then our earnings, our cash flows from operations, and the borrowing base under our revolving credit facilities may be adversely impacted. Prolonged periods of lower oil and natural gas prices or sustained wider differentials could cause us to not be in compliance with financial covenants under our revolving credit facilities and thereby affect our liquidity. However, we have protected a portion of our forecasted production through 2012 against declining commodity prices. Please read Item 3. Quantitative and Qualitative Disclosures about Market Risk and Note 5 of Notes to Consolidated Financial Statements included in Item 1. Financial Statements for additional information regarding our commodity derivative contracts.

Revolving credit facilities. The syndicate of lenders underwriting our revolving credit facility includes 29 banking and other financial institutions, and the syndicate of lenders underwriting ENP s revolving credit facility includes 12 banking and other financial

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institutions. None of the lenders are underwriting more than 16 percent of the respective total commitment. We believe the number of lenders, the small percentage participation of each, and the level of availability under each facility provides adequate diversity and flexibility should further consolidation occur within the financial services industry.

Encore Acquisition Company Senior Secured Credit Agreement

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. The EAC Credit Agreement matures on March 7, 2012. Effective March 10, 2009, we amended the EAC Credit Agreement to, among other things, increase the interest rate margins and commitment fees applicable to loans made under the EAC Credit Agreement. 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 the account of us 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 on April 1 and October 1 and upon requested special redeterminations. In March 2009, the borrowing base of our revolving credit facility was reaffirmed at $1.1 billion before a reduction of $200 million solely as a result of the monetization of certain of our 2009 oil derivative contracts during the first quarter of 2009. In addition, the provisions of the EAC Credit Agreement require the borrowing base to be reduced by 33 1/3 percent of the principal amount of the 9.5% Notes. As a result, the borrowing base on the EAC Credit Agreement was reduced by $75 million in April 2009. The reductions in the borrowing base under the EAC Credit Agreement did not result in any required prepayments of indebtedness. As of June 30, 2009, the borrowing base was $825 million.

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 commitment fee percentage under the EAC Credit Agreement:

Ratio of Total Outstanding Borrowings to Borrowing Base	Commitment Percentage
Less than .90 to 1	0.375%
Greater than or equal to .90 to 1	0.500%

Our obligations under the EAC Credit Agreement are secured by a first-priority security interest in substantially all of 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 outstanding borrowings 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	1.750%	0.500%
Greater than or equal to .50 to 1 but less than .75 to 1	2.000%	0.750%
Greater than or equal to .75 to 1 but less than .90 to 1	2.250%	1.000%
Greater than or equal to .90 to 1	2.500%	1.250%

The Eurodollar rate for any interest period (either one, two, three, or six months, as selected by us) is the rate equal to the British Bankers Association LIBOR Rate for deposits in dollars for a similar interest period. The Base Rate is calculated as the highest of: (1) the annual rate of interest announced by Bank of America, N.A. as its prime rate ;

(2) the federal funds effective rate plus 0.5 percent; or (3) except during a LIBOR Unavailability Period, the Eurodollar rate (for dollar deposits for a one-month term) for such day plus 1.0 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.

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

- 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 to consolidated current liabilities of not less than 1.0 to 1.0 (the EAC Current Ratio); and
- a requirement that we maintain a ratio of consolidated EBITDA to the sum of consolidated net interest expense plus letter of credit fees of not less than 2.5 to 1.0 (the EAC Total Interest Coverage Ratio).

In order to show EAC s compliance with the covenants of the EAC Credit Agreement, the use of non-GAAP financial measures is required. The presentation of these non-GAAP financial measures provides useful information to investors as they allow readers to understand how much cushion there is between the required ratios and the actual ratios. These non-GAAP financial measures should not be considered an alternative to any measure of financial performance presented in accordance with GAAP.

As of June 30, 2009, EAC was in compliance with all covenants in the EAC Credit Agreement, including the following financial covenants:

Financial Covenant	Required Ratio	Actual Ratio as of June 30, 2009
EAC Current Ratio	Minimum 1.0 to 1.0	3.2 to 1.0
EAC Total Interest Coverage Ratio	Minimum 2.5 to 1.0	11.2 to 1.0

The following table shows the calculation of the EAC Current Ratio as of June 30, 2009 ($ in thousands):

EAC current assets	$ 180,425
Availability under the EAC Credit Agreement	650,000
EAC consolidated current assets	$ 830,425
Divided by: EAC consolidated current liabilities	$ 261,227
EAC Current Ratio	3.2

The following table shows the calculation of the EAC Total Interest Coverage Ratio for the twelve months ended June 30, 2009 ($ in thousands):

EAC Consolidated EBITDA (a)	$671,832
Divided by: EAC consolidated net interest expense and letter of credit fees	$ 60,181
EAC Total Interest Coverage Ratio	11.2

(a) EAC Consolidated EBITDA is defined in the EAC Credit Agreement and generally means earnings before interest, income taxes, depletion, depreciation, and amortization, and exploration expense. EAC Consolidated EBITDA is a non-GAAP financial measure, which is reconciled to its most directly comparable GAAP measure below.

The following table presents a calculation of EAC Consolidated EBITDA for the twelve months ended June 30, 2009 (in thousands) as required under the EAC Credit Agreement, together with a reconciliation of such amount to its most directly comparable financial measures calculated and presented in accordance with GAAP. This EBITDA measure should not be considered an alternative to net income (loss), operating income (loss), cash flow from operating activities, or any other measure of financial performance or liquidity presented in accordance with GAAP. This EBITDA measure may not be comparable to similarly titled measures of another company because all companies may not calculate this measure in the same manner.

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EAC consolidated net income	$ 257,182
EAC unrealized non-cash hedge gain	(218,479)
EAC consolidated net interest expense	60,181
EAC income and franchise taxes	206,725
EAC depletion, depreciation, and amortization expense	231,914
EAC non-cash equity-based compensation	11,452
EAC exploration expense	108,631
EAC other non-cash	14,226
EAC Consolidated EBITDA	$ 671,832

The EAC Credit Agreement contains customary events of default, which would permit the lenders to accelerate the debt if not cured within applicable grace periods. 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.

On June 30, 2009 and July 31, 2009, there were $175 million of outstanding borrowings and $650 million of borrowing capacity under the EAC Credit Agreement.

Encore Energy Partners Operating LLC Credit Agreement

In March 2007, OLLC entered into a five-year credit agreement (as amended, the OLLC Credit Agreement) with a bank syndicate including Bank of America, N.A. and other lenders. The OLLC Credit Agreement matures on March 7, 2012. Effective March 10, 2009, OLLC amended the OLLC Credit Agreement to, among other things, increase the interest rate margins and commitment fees applicable to loans made under the OLLC Credit Agreement. 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.

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 on April 1 and October 1 and upon requested special redeterminations. As of June 30, 2009, the borrowing base was $240 million. In July 2009, ENP requested the syndicate of lenders underwriting the OLLC Credit Agreement to increase the borrowing base from $240 million to $375 million.

OLLC 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 commitment fee percentage under the OLLC Credit Agreement:

Ratio of Total Outstanding Borrowings to Borrowing Base	**Commitment Fee Percentage**
Less than .90 to 1	0.375%(a)
Greater than or equal to .90 to 1	0.500%

(a) In connection with the proposed increase in the borrowing base under the OLLC Credit Agreement from

$240 million to $375 million, ENP expects this commitment fee percentage to increase to 0.500 percent.

OLLC s obligations under the OLLC Credit Agreement are secured by a first-priority security interest in substantially all of OLLC s proved oil and natural gas reserves and in the equity interests of OLLC and 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 outstanding borrowings 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:

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Ratio of Total Outstanding Borrowings to Borrowing Base	Applicable Margin for Eurodollar Loans (a)	Applicable Margin for Base Rate Loans (a)
Less than .50 to 1	1.750%	0.750%
Greater than or equal to .50 to 1 but less than .75 to 1	2.000%	0.750%
Greater than or equal to .75 to 1 but less than .90 to 1	2.250%	1.000%
Greater than or equal to .90 to 1	2.500%	1.250%

(a) In connection with the proposed increase in the borrowing base under the OLLC Credit Agreement from $240 million to $375 million, ENP expects the applicable margin for Eurodollar loans to increase by 0.500 percent at each tier and the applicable margin for base rate loans to increase by 0.500 percent for the first tier and by 0.750 percent for the other three tiers.

The Eurodollar rate for any interest period (either one, two, three, or six months, as selected by ENP) is the rate equal to the British Bankers Association LIBOR Rate for deposits in dollars for a similar interest period. The Base Rate is calculated as the highest of: (1) the annual rate of interest announced by Bank of America, N.A. as its prime rate ; (2) the federal funds effective rate plus 0.5 percent; or (3) except during a LIBOR Unavailability Period, the Eurodollar rate (for dollar deposits for a one-month term) for such day plus 1.0 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, among others, include:

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 OLLC s 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 ENP and OLLC maintain a ratio of consolidated current assets to consolidated current liabilities of not less than 1.0 to 1.0 (the ENP Current Ratio);

a requirement that ENP and OLLC maintain a ratio of consolidated EBITDA to the sum of consolidated net interest expense plus letter of credit fees of not less than 1.5 to 1.0 (the ENP Total Interest Coverage Ratio);

a requirement that ENP and OLLC maintain a ratio of consolidated EBITDA to consolidated senior interest expense of not less than 2.5 to 1.0 (the ENP Senior Interest Coverage Ratio); and

a requirement that ENP and OLLC maintain a ratio of consolidated funded debt (excluding certain related party debt) to consolidated adjusted EBITDA of not more than 3.5 to 1.0 (the ENP Leverage Ratio).

In order to show ENP s and OLLC s compliance with the covenants of the OLLC Credit Agreement, the use of non-GAAP financial measures is required. The presentation of these non-GAAP financial measures provides useful information to investors as they allow readers to understand how much cushion there is between the required ratios and the actual ratios. These non-GAAP financial measures should not be considered an alternative to any measure of financial performance presented in accordance with GAAP.

As of June 30, 2009, ENP and OLLC were in compliance with all covenants in the OLLC Credit Agreement, including the following financial covenants:

Financial Covenant	**Required Ratio**	**Actual Ratio as of June 30, 2009**
ENP Current Ratio	Minimum 1.0 to 1.0	3.3 to 1.0
ENP Total Interest Coverage Ratio	Minimum 1.5 to 1.0	13.0 to 1.0
ENP Senior Interest Coverage Ratio	Minimum 2.5 to 1.0	17.2 to 1.0
ENP Leverage Ratio	Maximum 3.5 to 1.0	1.7 to 1.0

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The following table shows the calculation of the ENP Current Ratio as of June 30, 2009 ($ in thousands):

ENP current assets	$ 56,824
Availability under the OLLC Credit Agreement	45,000
ENP consolidated current assets	$ 101,824
Divided by: ENP consolidated current liabilities	$ 31,317
ENP Current Ratio	3.3

The following table shows the calculation of the ENP Total Interest Coverage Ratio for the twelve months ended June 30, 2009 ($ in thousands):

ENP Consolidated EBITDA (a)	$ 103,785
Divided by:	
ENP consolidated interest expense and letter of credit fees	$ 7,987
ENP consolidated interest income	(23)
ENP consolidated net interest expense and letter of credit fees	$ 7,964
ENP Total Interest Coverage Ratio	13.0

(a) ENP Consolidated EBITDA is defined in the OLLC Credit Agreement and generally means earnings before interest, income taxes, depletion, depreciation, and amortization, and exploration expense. ENP Consolidated EBITDA is a non-GAAP financial measure, which is reconciled to its most directly comparable GAAP measure below.

The following table shows the calculation of the ENP Senior Interest Coverage Ratio for the twelve months ended June 30, 2009 ($ in thousands):

ENP Consolidated EBITDA (a)	$ 103,785
Divided by:	
ENP consolidated senior interest expense	$ 6,045
ENP consolidated interest income	(23)
ENP consolidated net senior interest expense	$ 6,022
ENP Senior Interest Coverage Ratio	17.2

(a) ENP Consolidated EBITDA is defined in the OLLC Credit Agreement and generally means earnings before interest, income taxes, depletion, depreciation, and amortization, and exploration expense. ENP Consolidated EBITDA is a non-GAAP financial measure, which is reconciled to its most directly comparable GAAP measure below.

The following table shows the calculation of the ENP Leverage Ratio for the twelve months ended June 30, 2009 ($ in thousands):

ENP consolidated funded debt	$ 195,000
Divided by: ENP Consolidated Adjusted EBITDA (a)	$ 114,577
ENP Leverage Ratio	1.7

(a) ENP Consolidated Adjusted EBITDA is defined in the OLLC Credit

Agreement and generally means earnings before interest, income taxes, depletion, depreciation, and amortization, and exploration expense, after giving pro forma effect to one or more acquisitions or dispositions in excess of $20 million in the aggregate. ENP Consolidated Adjusted EBITDA is a non-GAAP financial measure, which is reconciled to its most directly comparable GAAP measure below.

The following table presents a calculation of ENP Consolidated EBITDA and ENP Consolidated Adjusted EBITDA for the twelve months ended June 30, 2009 (in thousands) as required under the OLLC Credit Agreement, together with a reconciliation of such amounts to their most directly comparable financial measures calculated and presented in accordance with GAAP. These EBITDA measures should not be considered an alternative to net income (loss), operating income (loss), cash flow from operating activities, or any other measure of financial performance or liquidity presented in accordance with GAAP. These EBITDA measures may not be comparable to similarly titled measures of another company because all companies may not calculate these measures in the same manner.

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ENP consolidated net income	$ 180,405
ENP unrealized non-cash hedge gain	(130,390)
ENP consolidated net interest expense	7,964
ENP income and franchise taxes	998
ENP depletion, depreciation, amortization, and exploration expense	41,202
ENP non-cash unit-based compensation	3,321
ENP other non-cash	285
ENP Consolidated EBITDA	103,785
Pro forma effect of acquisitions	10,792
ENP Consolidated Adjusted EBITDA	$ 114,577

The OLLC Credit Agreement contains customary events of default, which would permit the lenders to accelerate the debt if not cured within applicable grace periods. 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.

On June 30, 2009, there were $195 million of outstanding borrowings and $45 million of borrowing capacity under the OLLC Credit Agreement. On July 31, 2009, there were $150 million of outstanding borrowings and $90 million of borrowing capacity under the OLLC Credit Agreement.

Please read Note 7 of Notes to Consolidated Financial Statements included in Item 1. Financial Statements for additional information regarding our long-term debt.

Debt covenants. At June 30, 2009, we and ENP were in compliance with all debt covenants.

Capitalization. At June 30, 2009, we had total assets of $3.4 billion and total capitalization of $2.6 billion, of which 55 percent was represented by equity and 45 percent by long-term debt. At December 31, 2008, we had total assets of $3.6 billion and total capitalization of $2.8 billion, of which 53 percent was represented by equity and 47 percent by long-term debt. The percentages of our capitalization represented by 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 2008 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 exposure, but rather indicators of potential exposure. This information provides indicators of how we view and manage our ongoing market risk exposures. We do not enter into market risk sensitive instruments for speculative trading purposes.

The information included in Item 7A. Quantitative and Qualitative Disclosures about Market Risk in our 2008 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.

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Commodity Price Sensitivity

Our commodity derivative contracts are discussed in Note 5 of Notes to Consolidated Financial Statements included in Item 1. Financial Statements. The counterparties to our commodity derivative contracts are a diverse group of seven 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 June 30, 2009, the fair market value of our oil derivative contracts was a net asset of approximately $47.3 million and the fair market value of our natural gas derivative contracts was a net asset of approximately $25.7 million. These amounts exclude deferred premiums of $38.9 million that are not subject to changes in commodity prices. Based on our open commodity derivative positions at June 30, 2009, a 10 percent increase in the respective NYMEX prices for oil and natural gas would decrease our net commodity derivative asset by approximately $36.4 million, while a 10 percent decrease in the respective NYMEX prices for oil and natural gas would increase our net commodity derivative asset by approximately $38.3 million.

Interest Rate Sensitivity

Our long-term debt is discussed in Note 7 of Notes to Consolidated Financial Statements included in Item 1. Financial Statements. At June 30, 2009, we had total long-term debt of $1.2 billion, net of discount of $22.1 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, $225 million bears interest at a fixed rate of 9.5 percent, and $150 million bears interest at a fixed rate of 7.25 percent. The remaining long-term debt balance of $370 million as of June 30, 2009 consisted of outstanding borrowings under revolving credit facilities, which are subject to floating market rates of interest that are linked to the Eurodollar rate.

At this level of floating rate debt, if the Eurodollar rate increased by 10 percent, we would incur an additional $0.9 million of interest expense per year on revolving credit facilities, and if the Eurodollar rate decreased by 10 percent, we would incur $0.9 million less. Additionally, if the discount rates on our senior notes increased by 10 percent, we estimate the fair value of our fixed rate debt at June 30, 2009 would increase from approximately $724.7 million to approximately $734.7 million, and if the discount rates on our senior notes decreased by 10 percent, we estimate the fair value would decrease to approximately $714.7 million.

ENP s interest rate swaps are discussed in Note 5 of Notes to Consolidated Financial Statements included in Item 1. Financial Statements. As of June 30, 2009, the fair market value of ENP s interest rate swaps was a net liability of approximately $3.8 million. If the Eurodollar rate increased by 10 percent, we estimate the liability would decrease to approximately $3.4 million, and if the Eurodollar rate decreased by 10 percent, we estimate the liability would increase to approximately $4.2 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 our management, including our Chief Executive Officer and Chief Financial Officer, of the effectiveness of the design and operation of our disclosure controls and procedures. Based on that evaluation, our Chief Executive Officer and Chief Financial Officer concluded that our disclosure controls and procedures were effective as of June 30, 2009 to ensure that information required to be disclosed in the reports we file or submit 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 second quarter of 2009 that materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

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PART II. OTHER INFORMATION

Item 1. Legal Proceedings

We are a party to ongoing legal proceedings in the ordinary course of business. Management does not believe the result of these legal proceedings will have a material adverse effect on our business, financial condition, results of operations, or liquidity.

Item 1A. Risk Factors

In addition to the other information set forth in this Report, you should carefully consider the factors discussed in Item 1A. Risk Factors and elsewhere in our 2008 Annual Report on Form 10-K, which could materially affect our business, financial condition, or results of operations. The risks described in our 2008 Annual Report on Form 10-K are not the only risks we face. Unknown risks and uncertainties or risks and uncertainties that we currently believe to be immaterial may also have a material adverse effect on our business, financial condition, or results of operations.

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

Issuer Purchases of Equity Securities

In October 2008, the Board approved a share repurchase program authorizing us to repurchase up to $40 million of our common stock. As of June 30, 2009, 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 share repurchase program. During the second quarter of 2009, we did not repurchase any shares of our outstanding common stock under the share repurchase program. As of June 30, 2009, approximately $22.8 million of our common stock remained authorized for repurchase.

The following table summarizes purchases of our common stock during the second quarter of 2009:

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
April		$		
May (a)	466	$ 34.41		
June		$		
Total	466	$ 34.41		$ 22,830,139

(a) Certain employees directed us to withhold 466 shares of common stock to satisfy minimum tax withholding obligations in

conjunction
with the vesting
of restricted
stock awards.

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

Our annual meeting of stockholders was held on April 28, 2009. The items submitted to stockholders for vote were (1) the election of eight nominees to serve as directors until our next annual meeting and (2) the ratification of the appointment of Ernst & Young LLP as our independent registered public accounting firm for 2009. Notice of the meeting and proxy information was distributed to stockholders prior to the meeting in accordance with law. There were no solicitations in opposition to the nominees. Out of a total of 52,754,036 shares of our common stock outstanding and entitled to vote at the meeting, 50,091,968 shares (95.0 percent) were present in person or by proxy.

Election of Directors

The Board recommended that our stockholders elect all eight nominees to serve as our directors until our next annual meeting. The vote tabulation with respect to each nominee to the Board was as follows:

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NOMINEE	FOR	WITHHELD
I. Jon Brumley	31,100,906	18,991,062
Jon S. Brumley	30,942,150	19,149,818
John A. Bailey	31,239,381	18,852,587
Martin C. Bowen	31,239,182	18,852,786
Ted Collins, Jr.	31,115,413	18,976,555
Ted A. Gardner	31,239,381	18,852,587
John V. Genova	31,240,623	18,851,345
James A. Winne III	31,253,638	18,838,330

Appointment of Independent Registered Public Accounting Firm for 2009

The Board recommended that our stockholders ratify the appointment of Ernst & Young LLP as our independent registered public accounting firm for 2009. The vote tabulation with respect to the ratification of the appointment of the independent registered public accounting firm for 2009 was as follows:

FOR	AGAINST	ABSTAIN
49,965,408	109,497	17,063

Item 6. Exhibits

Exhibit No.	Description
3.1	Second Amended and Restated Certificate of Incorporation of Encore Acquisition Company (incorporated by reference from Exhibit 3.1 of 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 of 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 of 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 of 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	Indenture, dated as of November 16, 2005, among Encore Acquisition Company and Wells Fargo Bank, National Association with respect to Subordinated Debt Securities (incorporated by reference from Exhibit 4.1 to EAC s Current Report on Form 8-K, filed with the SEC on November 23, 2005).
4.2	Third Supplemental Indenture, dated as of April 27, 2009, among Encore Acquisition Company, the subsidiary guarantors party thereto, and Wells Fargo Bank, National Association, with respect to the 9.50% Senior Subordinated Notes due 2016 (incorporated by reference from Exhibit 4.2 to EAC s Current Report on Form 8-K, filed with the SEC on April 28, 2009).
4.3	Form of 9.50% Senior Subordinated Note due 2016 (included as Exhibit A to Exhibit 4.2 above).
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 (loss) to fixed charges.

* Filed herewith.

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ENCORE ACQUISITION COMPANY
SIGNATURE

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

ENCORE ACQUISITION COMPANY

Date: August 5, 2009

/s/ Andrea Hunter
Andrea Hunter
Vice President, Controller,
and Principal Accounting Officer
(Duly Authorized Signatory)