ENCORE ACQUISITION CO
Form 10-K
February 25, 2010

Table of Contents

UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549

Form 10-K

(Mark One)

þ **ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**
For the fiscal year ended December 31, 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)*

Registrant s telephone number, including area code: (817) 877-9955

Securities registered pursuant to Section 12(b) of the Act:

Title of each class	**Name of each exchange on which registered**
Common Stock	New York Stock Exchange
Rights to Purchase Series A Junior Participating Preferred Stock	New York Stock Exchange

Securities registered pursuant to Section 12(g) of the Act: None

Indicate by check mark if the registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act. Yes þ No o

Indicate by check mark if the registrant is not required to file reports pursuant to Section 13 or Section 15(d) of the Act. Yes o No þ

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 if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K is not contained herein and will not be contained, to the best of registrant s knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10-K or any amendment to this Form 10-K. þ

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

Large accelerated filer þ	Accelerated filer o	Non-accelerated filer o (Do not check if a smaller reporting company)	Smaller reporting company o

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

Aggregate market value of the voting and non-voting common equity held by non-affiliates computed by reference to the price at which the common equity of the registrant was last sold as of June 30, 2009 (the last business day of the registrant s most recently completed second fiscal quarter)	$ 1,522,208,999
Number of shares of Common Stock, $0.01 par value, outstanding as of February 17, 2010	55,988,169

DOCUMENTS INCORPORATED BY REFERENCE:
None

ENCORE ACQUISITION COMPANY

INDEX

Table of Contents

ENCORE ACQUISITION COMPANY

GLOSSARY

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

ASC. FASB Accounting Standards Codification.

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.

Bcf. One billion cubic feet, used in reference to natural gas.

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.

CO_2. Carbon dioxide.

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

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

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

Developed Acreage. The number of acres allocated or assignable to producing wells or wells capable of production.

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. An exploratory, development, or extension well that proves to be incapable of producing either oil or natural gas in sufficient quantities to justify completion as an oil or natural gas well.

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.

EOR. Enhanced oil recovery.

Exploratory Well. A well drilled to find a new field or to find a new reservoir in a field previously producing oil or natural gas in another reservoir.

Extension Well. A well drilled to extend the limits of a known reservoir.

Farm-out. Transfer of all or part of the operating rights from the working interest holder to an assignee, who assumes all or some of the burden of development, in return for an interest in the property. The assignor usually retains an overriding royalty, but may retain any type of interest.

FASB. Financial Accounting Standards Board.

Table of Contents

ENCORE ACQUISITION COMPANY

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.

Horizontal Drilling. A drilling operation in which a portion of a well is drilled horizontally within a productive or potentially productive formation, which usually yields a well which has the ability to produce higher volumes than a vertical well drilled in the same formation.

Lease Operating Expense (LOE). All direct and allocated indirect costs of producing hydrocarbons after completion of drilling and before 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.

MBOE/D. One thousand BOE per day.

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

Mcf/D. One Mcf per day.

Mcfe. One Mcf equivalent, calculated by converting oil to natural gas equivalent at a ratio of one Bbl of oil to six Mcf of natural gas.

Mcfe/D. One Mcfe per day.

MMBbl. One million Bbls.

MMBOE. One million BOE.

MMBtu. One million British thermal units. One British thermal unit is the quantity of heat required to raise the temperature of a one-pound mass of water by one degree Fahrenheit.

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.

NYSE. The New York Stock Exchange.

Oil. Crude oil, condensate, and NGLs.

Operator. The entity responsible for the exploration, development, and production of a well or lease.

Table of Contents

ENCORE ACQUISITION COMPANY

Present Value of Future Net Revenues (PV-10). The present value of estimated future revenues to be generated from the production of proved reserves, net of estimated future production and development costs, using prices and costs as of the date of estimation without future escalation, without giving effect to commodity derivative activities, non-property related expenses such as general and administrative expenses, debt service, depletion, depreciation, and amortization, and income taxes, discounted at an annual rate of 10 percent.

Production Margin. Wellhead revenues less production costs.

Production Taxes. Production expense attributable to production, ad valorem, and severance taxes.

Productive 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 or in which the cost of the required equipment is relatively minor compared to the cost of a new well.

Proved Reserves. The estimated quantities of hydrocarbons, which, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be economically producible from a given date forward from known reservoirs under existing conditions and operating methods.

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 projects in the same reservoir or an analogous reservoir, or by other evidence using reliable technology establishing reasonable certainty.

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

Reliable Technology. A grouping of one or more technologies (including computational methods) that have been field tested and have been demonstrated to provide reasonably certain results with consistency and repeatability in the formation being evaluated or in an analogous formation.

Reserves. Reserves are estimated remaining quantities of oil and natural gas and related substances anticipated to the economically producible, as of a given date, by application of development projects to known accumulations. In addition, there must exist, or there must be a reasonable expectation that there will exist, the legal right to produce or a revenue interest in the production, installed means of delivering oil and gas or related substances to market, and all permits and financing required to implement the project.

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.

SEC. The United States Securities and Exchange Commission.

Table of Contents

ENCORE ACQUISITION COMPANY

Secondary Recovery. Enhanced recovery of hydrocarbons from a reservoir beyond the hydrocarbons 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.

Standardized Measure. Future cash inflows from proved reserves, less future production costs, development costs, net abandonment costs, and income taxes, discounted at 10 percent per annum to reflect the timing of future net cash flows. Standardized Measure differs from PV-10 because Standardized Measure includes the effect of estimated future net abandonment costs and income taxes.

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

Undeveloped Acreage. Lease acreage on which wells have not been drilled or completed to a point that would permit the production of economic quantities of oil or natural gas regardless of whether such acreage contains proved reserves.

Unit. A specifically defined area within which acreage is treated as a single consolidated lease for operations and for allocations of costs and benefits without regard to ownership of the acreage. Units are established for the purpose of recovering hydrocarbons from specified zones or formations.

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.

Table of Contents

ENCORE ACQUISITION COMPANY

As used in this Report, references to EAC, we, our, us, or similar terms refer to Encore Acquisition Company and i subsidiaries, unless the context indicates otherwise. References to ENP refers to Encore Energy Partners LP and its subsidiaries. The financial position, results of operations, and cash flows of ENP are consolidated with those of EAC. This Report contains forward-looking statements, which give our current expectations or forecasts of future events. The Private Securities Litigation Reform Act of 1995 provides a safe harbor for forward-looking statements made by us or on our behalf. Please read Item 1A. Risk Factors for a description of various factors that could materially affect our ability to achieve the anticipated results described in the forward-looking statements. Certain terms commonly used in the oil and natural gas industry and in this Report are defined under the caption Glossary. In addition, all production and reserve volumes disclosed in this Report represent amounts net to us, unless otherwise noted.

PART I

ITEMS 1 and 2. ***BUSINESS AND PROPERTIES***

General

Our Business. We are a Delaware corporation engaged in the acquisition and development of oil and natural gas reserves from onshore fields in the United States. Since 1998, we have acquired producing properties with proven reserves and leasehold acreage and grown the production and proven reserves by drilling, exploring, reengineering, or expanding existing waterflood projects, and applying tertiary recovery techniques. Our 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.

In August 2009, we acquired certain oil and natural gas properties and related assets in the Mid-Continent and East Texas from EXCO Resources, Inc. (together with its affiliates, EXCO) for approximately $357.4 million in cash, substantially all of which are proved producing.

Merger with Denbury. On October 31, 2009, we entered into an Agreement and Plan of Merger (the Merger Agreement) with Denbury Resources Inc. (Denbury) pursuant to which we have agreed to merge with and into Denbury, with Denbury as the surviving entity (the Merger). The Merger Agreement, which was unanimously approved by our Board of Directors (the Board) and by Denbury s Board of Directors, provides for Denbury s acquisition of all of our issued and outstanding shares of common stock, par value $.01 per share, in a transaction valued at approximately $4.5 billion, including the assumption of debt and the value of our interest in ENP. We expect to complete the Merger during the first quarter of 2010, although completion by any particular date cannot be assured.

Proved Reserves. Our estimated total proved reserves at December 31, 2009 were 147.1 MMBbls of oil and 439.1 Bcf of natural gas, based on 2009 average market prices of $61.18 per Bbl for oil and $3.83 per Mcf for natural gas. On a BOE basis, our proved reserves were 220.3 MMBOE at December 31, 2009, of which 67 percent was oil, 80 percent was proved developed, and 20 percent was proved undeveloped.

Most Valuable Asset. The CCA represented approximately 32 percent of our total proved reserves as of December 31, 2009 and is our most valuable asset today and in the foreseeable future. A large portion of our future success revolves around current and future CCA exploitation and production through primary, secondary, and tertiary recovery techniques.

ENCORE ACQUISITION COMPANY

Drilling. In 2009, we drilled 34 gross (27.5 net) operated productive wells and participated in drilling 78 gross (14.8 net) non-operated productive wells for a total of 112 gross (42.3 net) productive wells. In 2009, we drilled six gross (5.9 net) operated dry holes and participated in drilling another two gross (0.6 net) dry holes for a total of eight gross (6.6 net) dry holes. This represents a success rate of over 93 percent during 2009. We invested $286.9 million in development, exploitation, and exploration activities in 2009, of which $25.4 million related to dry holes.

ENP. As of February 17, 2010, we owned 20,924,055 of ENP s outstanding common units, representing an approximate 45.7 percent limited partner interest. Through our indirect ownership of ENP s general partner, we also hold all 504,851 general partner units, representing a 1.1 percent general partner interest in ENP. As we control ENP s general partner, ENP s financial position, results of operations, and cash flows are consolidated with ours.

In February 2008, we 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 and 6,884,776 ENP common units. In determining the total sales price, the common units were valued at $125.0 million. In January 2009, we sold certain oil and natural gas 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. In June 2009, we sold certain oil and natural gas properties and related assets in the Williston Basin in North Dakota and Montana (the Williston Basin Assets) to ENP for approximately $25.2 million in cash. In August 2009, we sold 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) to ENP for approximately $179.6 million in cash.

Financial Information About Operating Segments. We have operations in only one industry segment: the oil and natural gas exploration and production industry in the United States. However, we are organizationally structured along two operating segments: EAC Standalone and ENP. The contribution of each operating segment to revenues and operating income (loss), and the identifiable assets and liabilities attributable to each operating segment, are set forth in Note 16 of Notes to Consolidated Financial Statements included in Item 8. Financial Statements and Supplementary Data.

Operations

Well Operations

In general, we seek to be the operator of wells in which we have a working interest. As operator, we design and manage the development of a well and supervise operation and maintenance activities on a day-to-day basis. We do not own drilling rigs or other oilfield service equipment used for drilling or maintaining wells on properties we operate. Independent contractors engaged by us provide all the equipment and personnel associated with these activities.

As of December 31, 2009, we operated properties representing approximately 79 percent of our proved reserves. As the operator, we are able to better control expenses, capital allocation, and the timing of exploitation and development activities on our properties. We also own working interests in properties that are operated by third parties for which we are required to pay our share of production, exploitation, and development costs. Please read Properties Nature of Our Ownership Interests. During 2009, 2008, and 2007, our development costs on non-operated properties were approximately 39 percent, 22 percent, and 40 percent, respectively, of our total development costs. We also own royalty interests in wells operated by third parties that are not burdened by production or capital costs; however, we have little or no control over the implementation of projects on these properties.

Table of Contents

ENCORE ACQUISITION COMPANY

Natural Gas Gathering

We own and operate a network of natural gas gathering systems in our Elk Basin area of operation. These systems gather and transport our natural gas and a small amount of third-party natural gas to larger gathering systems and intrastate, interstate, and local distribution pipelines. Our network of natural gas gathering systems permits us to transport production from our wells with fewer interruptions and also minimizes any delays associated with a gathering company extending its lines to our wells. Our ownership and control of these lines enables us to:

- realize faster connection of newly drilled wells to the existing system;
- control pipeline operating pressures and capacity to maximize our production;
- control compression costs and fuel use;
- maintain system integrity;
- control the monthly nominations on the receiving pipelines to prevent imbalances and penalties; and
- track sales volumes and receipts closely to assure all production values are realized.

Seasonal Nature of Business

Oil and natural gas producing operations are generally not seasonal. However, demand for some of our products can fluctuate season to season, which impacts price. In particular, heavy oil is typically in higher demand in the summer for its use in road construction, and natural gas is generally in higher demand in the winter for heating.

Table of Contents

ENCORE ACQUISITION COMPANY

Production and Price History

The following table sets forth information regarding our production volumes, average realized prices, and average costs per BOE for the periods indicated:

	Year Ended December 31, 2009	2008	2007
Total Production Volumes:			
Oil (MBbls)	10,016	10,050	9,545
Natural gas (MMcf)	33,919	26,374	23,963
Combined (MBOE)	15,669	14,446	13,539
Average Daily Production Volumes:			
Oil (Bbls/D)	27,441	27,459	26,152
Natural gas (Mcf/D)	92,928	72,060	65,651
Combined (BOE/D)	42,929	39,470	37,094
Average Realized Prices:			
Oil (per Bbl)	$ 54.85	$ 89.30	$ 58.96
Natural gas (per Mcf)	3.87	8.63	6.26
Combined (per BOE)	43.43	77.87	52.66
Average Costs per BOE:			
Lease operating	$ 10.53	$ 12.12	$ 10.59
Production, ad valorem, and severance taxes	4.44	7.66	5.51
Depletion, depreciation, and amortization	18.56	15.80	13.59
Impairment of long-lived assets	0.64	4.12	
Exploration	3.35	2.71	2.05
Derivative fair value loss (gain)	3.80	(23.97)	8.31
General and administrative	3.45	3.35	2.89
Provision for doubtful accounts	0.49	0.14	0.43
Other operating	1.64	0.90	1.26
Marketing, net of revenues	(0.05)	(0.06)	(0.11)

Productive Wells

The following table sets forth information relating to productive wells in which we owned a working interest at December 31, 2009. Wells are classified as oil or natural gas wells according to their predominant production stream. We also hold royalty interests in units and acreage beyond the wells in which we own a working interest.

	Oil Wells			Natural Gas Wells		
	Gross Wells(a)	Net Wells	Average Working Interest	Gross Wells(a)	Net Wells	Average Working Interest
CCA	729	645.2	89%	23	6.3	27%

Permian Basin	1,969	772.2	39%	692	353.5	51%
Rockies	1,476	851.7	58%	42	29.7	71%
Mid-Continent	484	282.6	58%	1,355	569.7	42%
Total	4,658	2,551.7	55%	2,112	959.2	45%

(a) Our total wells include 3,810 operated wells and 2,960 non-operated wells. At December 31, 2009, 62 of our wells had multiple completions.

4

Table of Contents

ENCORE ACQUISITION COMPANY

Acreage

The following table sets forth information relating to our leasehold acreage at December 31, 2009. Developed acreage is assigned to productive wells. Undeveloped acreage is acreage held under lease, permit, contract, or option that is not in a spacing unit for a producing well, including leasehold interests identified for exploitation or exploratory drilling. As of December 31, 2009, our undeveloped acreage in the Rockies represented approximately 40 percent of our total net undeveloped acreage. A portion of our oil and natural gas leases are held by production, which means that for as long as our wells continue to produce oil or natural gas, we will continue to own the lease. Leases which are not held by production expire at various dates between 2010 and 2020, with leases representing $28.9 million of cost set to expire in 2010 if not developed.

	Gross Acreage	Net Acreage
CCA:		
Developed	93,563	94,607
Undeveloped	159,264	133,107
	252,827	227,714
Permian Basin:		
Developed	81,248	53,788
Undeveloped	25,242	23,449
	106,490	77,237
Rockies:		
Developed	235,535	160,024
Undeveloped	375,704	245,170
	611,239	405,194
Mid-Continent:		
Developed	189,778	101,900
Undeveloped	292,504	205,703
	482,282	307,603
Total:		
Developed	600,124	410,319
Undeveloped	852,714	607,429
	1,452,838	1,017,748

Table of Contents

ENCORE ACQUISITION COMPANY

Development Results

The following table sets forth information with respect to wells completed during the periods indicated, regardless of when development was initiated. This information should not be considered indicative of future performance, nor should a correlation be assumed between productive wells drilled, quantities of reserves discovered, or economic value.

	Year Ended December 31,					
	2009		2008		2007	
	Gross	Net	Gross	Net	Gross	Net
Development Wells:						
Productive	57	25.9	186	73.4	165	61.7
Dry holes	1	1.0	5	3.1	5	3.3
	58	26.9	191	76.5	170	65.0
Exploratory Wells:						
Productive	55	16.4	96	31.4	63	20.9
Dry holes	7	5.6	8	3.8	5	2.6
	62	22.0	104	35.2	68	23.5
Total:						
Productive	112	42.3	282	104.8	228	82.6
Dry holes	8	6.6	13	6.9	10	5.9
	120	48.9	295	111.7	238	88.5

Present Activities

As of December 31, 2009, we had 25 gross (10.3 net) wells that had begun drilling and were in varying stages of drilling operations, of which nine gross (1.9 net) were development wells. As of December 31, 2009, we had 15 gross (6.0 net) wells that had reached total depth and were in the process of being completed pending first production, of which six gross (1.2 net) were development wells.

Delivery Commitments and Marketing Arrangements

Our oil and natural gas production is generally sold to marketers, processors, refiners, and other purchasers that have access to nearby pipeline, processing, and gathering facilities. In areas where there is no practical access to pipelines, oil is trucked to central storage facilities where it is aggregated and sold to various markets and downstream purchasers. Our production sales agreements generally contain customary terms and conditions for the oil and natural gas industry, provide for sales based on prevailing market prices in the area, and generally have terms of one year or less.

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 currently believe that we have been allocated sufficient pipeline capacity to move our crude oil production. However, there can be no assurance that we will be allocated sufficient pipeline capacity to move our crude oil production in the future. An expansion of the Enbridge Pipeline was completed in early 2008, which moved the total Rockies area pipeline takeaway closer to increasing production volumes and thereby provided greater stability to oil differentials in the area. An additional expansion of Enbridge Pipeline was completed in early

ENCORE ACQUISITION COMPANY

2010, bringing additional takeaway capacity to the region, but in spite of these increases in capacity, the Enbridge Pipeline continues to run at full capacity. The Enbridge pipeline is currently presenting a new proposal to further expand the line in anticipation of the continuing expected production increases from the Williston / Bakken region. However, any 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. The following table shows the relationship between oil and natural gas wellhead prices as a percentage of average NYMEX prices by quarter for 2009:

	First Quarter of 2009	Second Quarter of 2009	Third Quarter of 2009	Fourth Quarter of 2009
Average oil wellhead to NYMEX percentage	82%	92%	89%	89%
Average natural gas wellhead to NYMEX percentage	67%	105%	109%	112%

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 resulting in a price we were paid per Mcf under certain contracts to be higher than the average NYMEX price.

Principal Customers

For 2009, our largest purchaser was Eighty-Eight Oil, which accounted for approximately 18 percent of our total sales of production. Our marketing of oil and natural gas can be affected by factors beyond our control, the potential effects of which cannot be accurately predicted. Management believes that the loss of any one purchaser would not have a material adverse effect on our ability to market our oil and natural gas production.

Competition

The oil and natural gas industry is highly competitive. We encounter strong competition from other oil and natural gas companies in acquiring properties, contracting for development equipment, and securing trained personnel. Many of these competitors have resources substantially greater than ours. As a result, our competitors may be able to pay more for desirable leases, or to evaluate, bid for, and purchase a greater number of properties or prospects than our resources will permit.

We are also affected by competition for rigs and the availability of related equipment. The oil and natural gas industry has experienced shortages of rigs, equipment, pipe, and personnel, which has delayed development and exploitation activities and has caused significant price increases. We are unable to predict when, or if, such shortages may occur or how they would affect our development and exploitation program.

Competition is also strong for attractive oil and natural gas producing properties, undeveloped leases, and development rights, and we may not be able to compete satisfactorily when attempting to acquire additional properties.

Table of Contents

ENCORE ACQUISITION COMPANY

Properties

Nature of Our Ownership Interests

The following table sets forth the production, average wellhead prices, and average LOE per BOE of our properties by principal area of operation for the periods indicated:

	Production						
	Oil (MBbls)	Natural Gas (MMcf)	Total (MBOE)	Percent of Total	Average Oil Wellhead (per Bbl)	Average Natural Gas Wellhead (per Mcf)	Lease Operating (per BOE)
2009							
CCA	3,786	889	3,934	25%	$ 55.41	$ 3.87	$ 12.64
Permian Basin	1,217	15,182	3,748	24%	56.73	3.98	8.32
Rockies	4,410	2,035	4,749	30%	53.46	3.96	12.66
Mid-Continent	603	15,813	3,238	21%	57.77	3.74	7.43
Total	10,016	33,919	15,669	100%	54.85	3.87	10.53
2008							
CCA	4,146	978	4,309	30%	88.66	8.35	12.62
Permian Basin	1,246	12,442	3,320	23%	95.34	8.65	11.96
Rockies	4,256	1,870	4,567	32%	88.15	9.02	13.80
Mid-Continent	402	11,084	2,250	15%	96.28	8.55	8.02
Total	10,050	26,374	14,446	100%	89.58	8.63	12.12
2007							
CCA	4,426	1,122	4,614	34%	62.72	5.31	10.16
Permian Basin	1,214	8,937	2,703	20%	67.88	7.03	11.97
Rockies	3,434	1,368	3,662	27%	62.61	6.31	12.15
Mid-Continent	471	12,536	2,560	19%	65.98	6.62	7.69
Total	9,545	23,963	13,539	100%	63.50	6.69	10.59

Table of Contents

ENCORE ACQUISITION COMPANY

The following table sets forth the proved reserves of our properties by principal area of operation as of December 31, 2009:

	Oil (MBbls)	Natural Gas (MMcf)	Total (MBOE)	Percent of Total
Proved Developed:				
CCA	60,227	12,708	62,345	36%
Permian Basin	14,408	127,620	35,678	20%
Rockies	39,274	15,448	41,849	24%
Mid-Continent	7,492	166,646	35,266	20%
Total Proved Developed	121,401	322,422	175,138	100%
Proved Undeveloped:				
CCA	7,777	675	7,890	17%
Permian Basin	5,641	38,886	12,122	27%
Rockies	11,469	6,725	12,590	28%
Mid-Continent	806	70,364	12,533	28%
Total Proved Undeveloped	25,693	116,650	45,135	100%
Total Proved:				
CCA	68,004	13,383	70,235	32%
Permian Basin	20,049	166,506	47,800	22%
Rockies	50,743	22,173	54,439	24%
Mid-Continent	8,298	237,010	47,799	22%
Total Proved	147,094	439,072	220,273	100%

The following table sets forth the PV-10 of our properties by principal area of operation as of December 31, 2009:

	Amount(a) (In thousands)	Percent of Total
CCA	$ 786,720	37%
Permian Basin	419,346	20%
Rockies	671,483	31%
Mid-Continent	263,488	12%
Total	$ 2,141,037	100%

(a) Giving effect to commodity derivative contracts, our PV-10 would decrease by $23.4 million at December 31, 2009. Standardized Measure at December 31, 2009 was $1.7 billion. Standardized Measure differs from PV-10 by approximately $414.0 million because Standardized Measure includes the effects of future net abandonment costs and future income taxes. Since we are taxed at the corporate level, future income taxes are determined on a combined property basis and cannot be accurately subdivided among our core areas. Therefore, we believe PV-10 provides the best method for assessing the relative value of each of our areas.

Recent SEC Rule-Making Activity. In December 2008, the SEC announced that it had approved revisions designed to modernize the oil and gas company reserves reporting requirements. Application of the new reserve rules resulted in the use of lower prices at December 31, 2009 for both oil and natural gas than would have resulted under the previous rules. Use of new 12-month average pricing rules at December 31, 2009 resulted in a decrease in proved reserves of approximately 8.5 MBOE while the change in definition of proved

ENCORE ACQUISITION COMPANY

undeveloped reserves increased total proved reserves by 5.7 MMBOE. Therefore, the total impact of the new reserve rules resulted in negative reserves revisions of 2.8 MMBOE. Pursuant to the SEC s final rule, prior period reserves were not restated.

The SEC s new rules expanded the technologies that a company can use to establish reserves. The SEC now allows use of techniques that have been proved effective by actual production from projects in the same reservoir or an analogous reservoir or by other evidence using reliable technology that establishes reasonable certainty.

We used a combination of production and pressure performance, wireline wellbore measurements, simulation studies, offset analogies, seismic data and interpretation, wireline formation tests, geophysical logs, and core data to calculate our reserves estimates, including the material additions to the 2009 reserves estimates.

Proved Undeveloped Reserves (PUDs). As of December 31, 2009, our PUDs totaled 25.7 MMBbls of crude oil and 116.7 Bcf of natural gas, for a total of 45.1 MMBOE or about 20.5 percent of our total proved reserves.

All of our PUDs as of December 31, 2009 are associated with drilling or improved recovery development projects that are scheduled to begin drilling or implementation within the next 5 years. Our major development areas include drilling locations in West Texas, Bakken, and Haynesville and PUDs booked for secondary recovery projects in CCA and West Texas. All of the drilling projects will have PUDs convert from undeveloped to developed as these projects begin production. All of the improved recovery projects will convert to proved developed reserves as, and to the extent, these projects achieve production response.

Changes in PUDs that occurred during 2009 were due to:

- reclassifications of PUDs into proved developed reserves for implementation of drilling projects and response to secondary/tertiary recovery projects;
- additions of PUDs due to proving up additional drilling locations and changes in PUDs definition under the new SEC rules; and
- negative revisions in PUDs due to changes in commodity prices.

Drilling Plans. All PUD drilling locations are scheduled to be drilled prior to the end of 2014. Initial production from these PUDs is expected to begin between 2010 to 2014.

Internal Controls Over Reserves Estimates. Our policies regarding internal controls over the recording of reserves estimates requires reserves to be in compliance with the SEC definitions and guidance and prepared in accordance with generally accepted petroleum engineering principles. We engage a third-party petroleum consulting firm, Miller and Lents, to prepare our reserves. Responsibility for compliance in reserves bookings is delegated to the Reserves and Planning Engineering Manager and requires that reserves estimates be made by the regional reservoir engineering staff for our different geographical regions. These reserves estimates are reviewed and approved by regional management and senior engineering staff with final approval by the Reserves and Planning Engineering Manager and the Senior Vice President and Chief Operating Officer and certain members of senior management.

Our Reserves and Planning Engineering Manager is the technical person primarily responsible for overseeing the preparation of our reserves estimates. She has a Bachelor of Science degree in Petroleum Engineering, 15 years of industry experience, and 9 years experience managing our reserves with positions of increasing responsibility in engineering and evaluations. The Reserves and Planning Engineering Manager reports directly to our Senior Vice President and Chief Operating Officer.

The engineers and geologists of Miller and Lents have an average of 30 years of relevant industry experience in the estimation, assessment, and evaluation of oil and natural gas reserves. They have significant industry experience in virtually all petroleum-producing basins in the world and meet the requirements

Table of Contents

ENCORE ACQUISITION COMPANY

regarding qualifications, independence, objectivity, and confidentiality set forth in the Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserves Information promulgated by the Society of Petroleum Engineers. Miller and Lents is an independent firm of petroleum engineers, geologists, geophysicists, and petrophysicists; it does not own an interest in our properties and is not employed on a contingent fee basis. Miller and Lents report on our reserves and future net revenues as of December 31, 2009, which details specific information regarding the scope of work undertaken and the results thereof, is filed as Exhibit 99.1 to this Report and incorporated herein by reference.

Guidelines established by the SEC were used to prepare these reserve estimates. Oil and natural gas reserve engineering is and must be recognized as a subjective process of estimating underground accumulations of oil and natural gas that cannot be measured in an exact way, and estimates of other engineers might differ materially from those included herein. The accuracy of any reserve estimate is a function of the quality of available data and engineering, and estimates may justify revisions based on the results of drilling, testing, and production activities. Accordingly, reserve estimates and their PV-10 are inherently imprecise, subject to change, and should not be construed as representing the actual quantities of future production or cash flows to be realized from oil and natural gas properties or the fair market value of such properties.

Other Reserve Information. During 2009, we filed the estimates of our oil and natural gas reserves as of December 31, 2008 with the U.S. Department of Energy on Form EIA-23. As required by Form EIA-23, the filing reflected only gross production that comes from our operated wells at year-end. Those estimates came directly from our reserve report prepared by Miller and Lents.

Table of Contents

ENCORE ACQUISITION COMPANY

CCA Properties

Our initial purchase of interests in the CCA was in 1999, and we continue to acquire additional working interests. As of December 31, 2009, we operated virtually all of our CCA properties with an average working interest of approximately 89 percent in the oil wells and 27 percent in the natural gas wells.

The CCA is a major structural feature of the Williston Basin in southeastern Montana and northwestern North Dakota. Our acreage is concentrated on the two-to-six-mile-wide crest of the CCA, giving us access to the greatest accumulation of oil in the structure. Our holdings extend for approximately 120 continuous miles along the crest of the CCA across five counties in two states. Primary producing reservoirs are the Red River, Stony Mountain, Interlake, and Lodgepole formations at depths of between 7,000 and 9,000 feet. Our fields in the CCA include the North Pine, South Pine, Cabin Creek, Coral Creek, Little Beaver, Monarch, Glendive North, Glendive, Gas City, and Pennel fields.

Our CCA reserves are primarily produced through waterfloods. Our average daily net production from the CCA decreased 15 percent to 10,360 BOE/D in the fourth quarter of 2009 as compared to 12,153 BOE/D in the fourth quarter of 2008. We invested $18.1 million, $37.3 million, and $41.6 million in capital projects in the CCA during 2009, 2008, and 2007, respectively.

The CCA represents approximately 32 percent of our total proved reserves as of December 31, 2009 and is our most valuable asset today and in the foreseeable future. A large portion of our future success revolves around current and future exploitation of and production from this area.

We pursued HPAI in the CCA beginning in 2002 because CO_2 was not readily available and HPAI was an attractive alternative. The initial project was successful and continues to be successful; however, the political environment is changing in favor of CO_2 sequestration. Therefore, we have made a strategic decision to move away from HPAI and focus on CO_2.

Existing HPAI project areas in the CCA are in Pennel and Cedar Creek fields. In both fields, HPAI wells will be converted to water injection in three to four phases over a period of approximately 18 months. Priority will be largely based on economics of incremental production uplift and air injection utilization. We anticipate that we will continue injecting air in a small number of HPAI patterns beyond the planned 18-month conversion period. We expect to realize significant LOE savings while achieving current production estimates.

Net Profits Interest. A major portion of our acreage position in the CCA is subject to net profits interests ranging from one percent to 50 percent. The holders of these net profits interests are entitled to receive a fixed percentage of the cash flow remaining after specified costs have been subtracted from net revenue. The net profits calculations are contractually defined. In general, net profits are determined after considering operating expense, overhead expense, interest expense, and development costs. The amounts of reserves and production attributable to net profits interests are deducted from our reserves and production data, and our revenues are reported net of net profits interests. The reserves and production attributed to net profits interests are calculated by dividing estimated future net profits interests (in the case of reserves) or prior period actual net profits interests (in the case of production) by commodity prices at the determination date. Fluctuations in commodity prices and the levels of development activities in the CCA from period to period will impact the reserves and production attributable to the net profits interests and will have an inverse effect on our reported reserves and production. For 2009, 2008, and 2007, we reduced oil and natural gas revenues for net profits interests by $31.8 million, $56.5 million, and $32.5 million, respectively.

Permian Basin Properties

West Texas. Our West Texas properties include 17 operated fields, including the East Cowden Grayburg Unit, Fuhrman-Mascho, Crockett County, Sand Hills, Howard Glasscock, Nolley, Deep Rock, and others; and seven non-operated fields. Production from the central portion of the Permian Basin comes from multiple reservoirs, including the Grayburg, San Andres, Glorieta, Clearfork, Wolfcamp, and Pennsylvanian zones.

ENCORE ACQUISITION COMPANY

Production from the southern portion of the Permian Basin comes mainly from the Canyon, Devonian, Ellenberger, Mississippian, Montoya, Strawn, and Wolfcamp formations with multiple pay intervals.

In March 2006, we entered into a joint development agreement with ExxonMobil Corporation (ExxonMobil) to develop legacy natural gas fields in West Texas. The agreement covers certain formations in the Parks, Pegasus, and Wilshire Fields in Midland and Upton Counties, the Brown Bassett Field in Terrell County, and Block 16, Coyanosa, and Waha Fields in Ward, Pecos, and Reeves Counties. Targeted formations include the Barnett, Devonian, Ellenberger, Mississippian, Montoya, Silurian, Strawn, and Wolfcamp horizons.

Under the terms of the agreement, we have the opportunity to develop approximately 100,000 gross acres. We earn 30 percent of ExxonMobil s working interest and 22.5 percent of ExxonMobil s net revenue interest in each well drilled. We operate each well during the drilling and completion phase, after which ExxonMobil assumes operational control of the well. We also have the right to propose and drill wells for as long as we are engaged in continuous drilling operations.

We entered into a side letter agreement with ExxonMobil to: (1) combine a group of specified fields into one development area, and extend the period within which we must drill a well in this development area and one additional development area in order to be considered as conducting continuous drilling operations; (2) transfer ExxonMobil s full working interest in a specified well along with a majority of its net royalty interest to us, while reserving its portion of an overriding royalty interest; (3) allow ExxonMobil to participate in any re-entry of the specified well under the original terms of a subsequent well (as defined in the joint development agreement), in which they will pay their proportional share of agreed costs incurred; and (4) reduce the non-consent penalty for 10 specified wells from 200 percent to 150 percent in exchange for ExxonMobil agreeing not to elect the carry for reduced working interest option for these wells.

Average daily production for our West Texas properties increased three percent from 8,497 BOE/D in the fourth quarter of 2008 to 8,777 BOE/D in the fourth quarter of 2009. We believe these properties will be an area of growth over the next several years. During 2009, we drilled 21 gross wells and invested approximately $64.3 million of capital to develop these properties.

New Mexico. We began investing in New Mexico in May 2006 with the strategy of deploying capital to develop low- to medium-risk development projects in southeastern New Mexico where multiple reservoir targets are available. Average daily production for these properties decreased 30 percent from 6,732 Mcfe/D in the fourth quarter of 2008 to 4,742 Mcfe/D in the fourth quarter of 2009. During 2009, we drilled two gross wells and invested approximately $3.3 million of capital to develop these properties.

Mid-Continent Properties

Oklahoma, Arkansas, and Kansas. We own various interests, including operated, non-operated, royalty, and mineral interests, on properties located in the Anadarko Basin of western Oklahoma and the Arkoma Basin of eastern Oklahoma and western Arkansas. Our average daily production for these properties nearly tripled from 8,159 Mcfe/D in the fourth quarter of 2008 to 24,420 Mcfe/D for the fourth quarter of 2009. The increase in production was primarily due to our acquisition of the Nogre Marchand Unit and other properties in the Anadarko basin from EXCO in 2009. During 2009, we invested $6.7 million of development and exploration capital in these properties.

North Louisiana Salt Basin and East Texas Basin. Our North Louisiana Salt Basin and East Texas Basin properties consist of operated working interests, non-operated working interests, and undeveloped leases and development in the Stockman, Danville, Gladewater, and Overton fields in east Texas. We purchased interests in the Gladewater and Overton fields from EXCO in 2009. Our interests in the Elm Grove Field in Bossier Parish, Louisiana include non-operated working interests ranging from one percent to 47 percent across 1,800 net acres in 15 sections.

ENCORE ACQUISITION COMPANY

Our East Texas and North Louisiana properties are in the same core area and have similar geology. The properties are producing primarily from multiple tight sandstone reservoirs in the Travis Peak and Lower Cotton Valley formations at depths ranging from 8,000 to 11,500 feet.

In the fourth quarter of 2008, we began our Haynesville shale drilling program with the spudding of the first Haynesville shale well at the Greenwood Waskom field in Caddo Parish, Louisiana. This well reached total depth in January 2009 ahead of schedule and was completed with an 11-stage fracture stimulation. Since entering the Haynesville play, we have accumulated over 18,000 gross acres.

During 2009, we drilled four gross wells and invested approximately $93.7 million of capital to develop these properties. Average daily production for these properties increased 30 percent from 36,239 Mcfe/D in the fourth quarter of 2008 to 47,104 Mcfe/D for the fourth quarter of 2009.

Rockies Properties

Big Horn Basin. In March 2007, ENP acquired the Big Horn Basin properties, which are located in the Big Horn Basin in northwestern Wyoming and south central Montana. The Big Horn Basin is characterized by oil and natural gas fields with long production histories and multiple producing formations. The Big Horn Basin is a prolific basin and has produced over 1.8 billion Bbls of oil since its discovery in 1906.

ENP also owns and operates (1) the Elk Basin natural gas processing plant near Powell, Wyoming, (2) the Clearfork crude oil pipeline extending from the South Elk Basin Field to the Elk Basin Field in Wyoming, (3) the Wildhorse natural gas gathering system that transports low sulfur natural gas from the Elk Basin and South Elk Basin fields to our Elk Basin natural gas processing plant, and (4) a natural gas gathering system that transports higher sulfur natural gas from the Elk Basin Field to our Elk Basin natural gas processing facility.

Average daily production for these properties decreased seven percent from 4,212 BOE/D in the fourth quarter of 2008 to 3,934 BOE/D in the fourth quarter of 2009. During 2009, we invested approximately $1.0 million of capital to develop these properties.

Williston Basin. Our Williston Basin properties have historically consisted of working and overriding royalty interests in several geographically concentrated fields. The properties are located in western North Dakota and eastern Montana, near our CCA properties. In April 2007, we acquired additional properties in the Williston Basin including 50 different fields across Montana and North Dakota. As part of this acquisition, we also acquired approximately 70,000 net unproved acres in the Bakken play of Montana and North Dakota. Since the acquisition, we have increased our acreage position in the Bakken play to approximately 300,000 acres. During 2009, we drilled and completed six wells in the Bakken and Sanish. The Almond prospect contains 70,000 net acres and is located near the northeast border of Mountrail County, North Dakota.

Average daily production for these properties increased 11 percent from 6,919 BOE/D in the fourth quarter of 2008 to 7,708 BOE/D in the fourth quarter of 2009. During 2009, we drilled seven gross wells and invested approximately $81.2 million of capital to develop our Rockies properties.

Bell Creek. Our Bell Creek properties are located in the Powder River Basin of southeastern Montana. We operate seven production units in Bell Creek, each with a 100 percent working interest. The shallow (less than 5,000 feet) Cretaceous-aged Muddy Sandstone reservoir produces oil. We have successfully implemented a polymer injection program on both injection and producing wells on our Bell Creek properties whereby a polymer is injected into a well to reduce the amount of water cycling in the higher permeability interval of the reservoir, reducing operating costs and increasing reservoir recovery. This process is generally more efficient than standard waterflooding.

ENCORE ACQUISITION COMPANY

We invested $12.3 million of capital to develop these properties in 2009. Average daily production from these properties increased nine percent from 890 BOE/D in the fourth quarter of 2008 to 969 BOE/D in the fourth quarter of 2009.

In July 2009, we acquired a private company for $24 million, which procured a CO_2 supply intended to be used for a tertiary oil recovery project in the Bell Creek Field. The initial term of the CO_2 supply contract is 15 years. The CO_2 purchasable is not transportable as capture and compression facilities and a related pipeline need to be built. Until the CO_2 can be transported to the field and the capture, compression, and injection of the CO_2 proves economic, the contract has an unknown useful life. During 2009, we invested approximately $5.0 million of capital related to a pipeline which is intended to be used to transport this CO_2 supply to our Bell Creek field.

Paradox Basin. The Paradox Basin properties, located in southeast Utah s Paradox Basin, are divided between two prolific oil producing units: the Ratherford Unit and the Aneth Unit. We believe these properties have additional potential in horizontal redevelopment, secondary development, and tertiary recovery potential.

Average daily production for these properties increased approximately four percent from 631 BOE/D in the fourth quarter of 2008 to 658 BOE/D in the fourth quarter of 2009. During 2009, we invested approximately $3.1 million of capital to develop these properties.

Title to Properties

We believe that we have satisfactory title to our oil and natural gas properties in accordance with standards generally accepted in the oil and natural gas industry.

Our properties are subject, in one degree or another, to one or more of the following:

- royalties, overriding royalties, net profits interests, and other burdens under oil and natural gas leases;
- contractual obligations, including, in some cases, development obligations arising under joint operating agreements, farm-out agreements, production sales contracts, and other agreements that may affect the properties or their titles;
- liens that arise in the normal course of operations, such as those for unpaid taxes, statutory liens securing unpaid suppliers and contractors, and contractual liens under joint operating agreements;
- pooling, unitization, and communitization agreements, declarations, and orders; and
- easements, restrictions, rights-of-way, and other matters that commonly affect property.

We believe that the burdens and obligations affecting our properties do not in the aggregate materially interfere with the use of the properties. As previously discussed, a major portion of our acreage position in the CCA, our primary asset, is subject to net profits interests.

We have granted mortgage liens on substantially all of our oil and natural gas properties in favor of Bank of America, N.A., as agent, to secure borrowings under our revolving credit facility. These mortgages and the revolving credit facility contain substantial restrictions and operating covenants that are customarily found in loan agreements of this type.

Environmental Matters and Regulation

General. Our operations are subject to stringent and complex federal, state, and local laws and regulations governing environmental protection, including air emissions, water quality, wastewater discharges, and solid waste management. These laws and regulations may, among other things:

- require the acquisition of various permits before development commences;
- require the installation of pollution control equipment;

ENCORE ACQUISITION COMPANY

- enjoin some or all of the operations of facilities deemed in non-compliance with permits;
- restrict the types, quantities, and concentration of various substances that can be released into the environment in connection with oil and natural gas development, production, and transportation activities;
- restrict the way in which wastes are handled and disposed;
- limit or prohibit development activities on certain lands lying within wilderness, wetlands, areas inhabited by threatened or endangered species, and other protected areas;
- require remedial measures to mitigate pollution from former and ongoing operations, such as requirements to close pits and plug abandoned wells;
- impose substantial liabilities for pollution resulting from operations; and
- require preparation of a Resource Management Plan, an Environmental Assessment, and/or an Environmental Impact Statement for operations affecting federal lands or leases.

These laws, rules, and regulations may also restrict the rate of oil and natural gas production below the rate that would otherwise be possible. The regulatory burden on the oil and natural gas industry increases the cost of doing business in the industry and consequently affects profitability. Additionally, Congress and federal and state agencies frequently revise environmental laws and regulations, and the clear trend in environmental regulation is to place more restrictions and limitations on activities that may affect the environment. Any changes that result in indirect compliance costs or additional operating restrictions, including costly waste handling, disposal, and cleanup requirements for the oil and natural gas industry could have a significant impact on our operating costs.

The following is a discussion of relevant environmental and safety laws and regulations that relate to our operations.

Waste Handling. The Resource Conservation and Recovery Act (RCRA), and comparable state statutes, regulate the generation, transportation, treatment, storage, disposal, and cleanup of hazardous and non-hazardous solid wastes. Under the auspices of the federal Environmental Protection Agency (the EPA), the individual states administer some or all of the provisions of RCRA, sometimes in conjunction with their own, more stringent requirements. Drilling fluids, produced waters, and most of the other wastes associated with the exploration, development, and production of crude oil or natural gas are regulated under RCRA s non-hazardous waste provisions. However, it is possible that certain oil and natural gas exploration and production wastes now classified as non-hazardous could be classified as hazardous wastes in the future. Any such change could result in an increase in our costs to manage and dispose of wastes, which could have a material adverse effect on our results of operations and financial position. Also, in the course of our operations, we generate some amounts of ordinary industrial wastes, such as paint wastes, waste solvents, and waste oils that may be regulated as hazardous wastes.

Site Remediation. The Comprehensive Environmental Response, Compensation and Liability Act (CERCLA), also known as the Superfund law, imposes joint and several liability, without regard to fault or legality of conduct, on classes of persons who are considered to be responsible for the release of a hazardous substance into the environment. These persons include the current and past owner or operator of the site where the release occurred, and anyone who disposed of or arranged for the disposal of a hazardous substance released at the site. Under CERCLA, such persons may be subject to joint and several liability for the costs of cleaning up the hazardous substances that have been released into the environment, for damages to natural resources, and for the costs of certain health studies. CERCLA authorizes the EPA, and in some cases third parties, to take actions in response to threats to the public health or the environment and to seek to recover from the responsible classes of persons the costs they incur. In addition, it is not uncommon for neighboring landowners and other third parties to file claims for personal injury and property damage allegedly caused by the hazardous substances released into the environment.

ENCORE ACQUISITION COMPANY

We own, lease, or operate numerous properties that have been used for oil and natural gas exploration and production for many years. Although petroleum, including crude oil, and natural gas are excluded from CERCLA s definition of hazardous substance, in the course of our ordinary operations, we generate wastes that may fall within the definition of a hazardous substance. We believe that we have utilized operating and waste disposal practices that were standard in the industry at the time, yet hazardous substances, wastes, or hydrocarbons may have been released on or under the properties owned or leased by us, or on or under other locations, including off-site locations, where such substances have been taken for disposal. In addition, some of our properties have been operated by third parties or by previous owners or operators whose treatment and disposal of hazardous substances, wastes, or hydrocarbons was not under our control. In fact, there is evidence that petroleum spills or releases have occurred in the past at some of the properties owned or leased by us. These properties and the substances disposed or released on them may be subject to CERCLA, RCRA, and analogous state laws. Under such laws, we could be required to remove previously disposed substances and wastes, remediate contaminated property, or perform remedial plugging or pit closure operations to prevent future contamination.

ENP s Elk Basin assets have been used for oil and natural gas exploration and production for many years. There have been known releases of hazardous substances, wastes, or hydrocarbons at the properties, and some of these sites are undergoing active remediation. The risks associated with these environmental conditions, and the cost of remediation, were assumed by ENP, subject only to limited indemnity from the seller of the Elk Basin assets. Releases may also have occurred in the past that have not yet been discovered, which could require costly future remediation. In addition, ENP assumed the risk of various other unknown or unasserted liabilities associated with the Elk Basin assets that relate to events that occurred prior to ENP s acquisition. If a significant release or event occurred in the past, the liability for which was not retained by the seller or for which indemnification from the seller is not available, it could adversely affect our results of operations, financial position, and cash flows.

ENP s Elk Basin assets include a natural gas processing plant. Previous environmental investigations of the Elk Basin natural gas processing plant indicate historical soil and groundwater contamination by hydrocarbons and the presence of asbestos-containing material at the site. Although the environmental investigations did not identify an immediate need for remediation of the suspected historical contamination, the extent of the contamination is not known and, therefore, the potential liability for remediating this contamination may be significant. In the event ENP ceased operating the gas plant, the cost of decommissioning it and addressing the previously identified environmental conditions and other conditions, such as waste disposal, could be significant. ENP does not anticipate ceasing operations at the Elk Basin natural gas processing plant in the near future nor a need to commence remedial activities at this time. However, a regulatory agency could require ENP to investigate and remediate any contamination even while the gas plant remains in operation. As of December 31, 2009, ENP has recorded $4.7 million as future abandonment liability for decommissioning the Elk Basin natural gas processing plant. Due to the significant uncertainty associated with the known and unknown environmental liabilities at the gas plant, ENP s estimate of the future abandonment liability includes a large contingency. ENP s estimates of the future abandonment liability and compliance costs are subject to change and the actual cost of these items could vary significantly from those estimates.

Water Discharges. The Clean Water Act (CWA), and analogous state laws, impose strict controls on the discharge of pollutants, including spills and leaks of oil and other substances, into waters of the United States. The discharge of pollutants into regulated waters is prohibited, except in accordance with the terms of a permit issued by the EPA or an analogous state agency. CWA regulates storm water run-off from oil and natural gas facilities and requires a storm water discharge permit for certain activities. Such a permit requires the regulated facility to monitor and sample storm water run-off from its operations. CWA and regulations implemented thereunder also prohibit discharges of dredged and fill material in wetlands and other waters of the United States unless authorized by an appropriately issued permit.

Spill prevention, control, and countermeasure requirements of CWA require appropriate containment berms and similar structures to help

ENCORE ACQUISITION COMPANY

prevent the contamination of navigable waters in the event of a petroleum hydrocarbon tank spill, rupture, or leak. Federal and state regulatory agencies can impose administrative, civil, and criminal penalties for non-compliance with discharge permits or other requirements of CWA and analogous state laws and regulations.

The primary federal law for oil spill liability is the Oil Pollution Act (OPA), which addresses three principal areas of oil pollution prevention, containment, and cleanup. OPA applies to vessels, offshore facilities, and onshore facilities, including exploration and production facilities that may affect waters of the United States. Under OPA, responsible parties, including owners and operators of onshore facilities, may be subject to oil cleanup costs and natural resource damages as well as a variety of public and private damages that may result from oil spills.

Air Emissions. Oil and natural gas exploration and production operations are subject to the federal Clean Air Act (CAA), and comparable state laws and regulations. These laws and regulations regulate emissions of air pollutants from various industrial sources, including oil and natural gas exploration and production facilities, and also impose various monitoring and reporting requirements. Such laws and regulations may require a facility to obtain pre-approval for the construction or modification of certain projects or facilities expected to produce air emissions or result in the increase of existing air emissions, obtain and strictly comply with air permits containing various emissions and operational limitations, or utilize specific emission control technologies to limit emissions.

Permits and related compliance obligations under CAA, as well as changes to state implementation plans for controlling air emissions in regional non-attainment areas, may require oil and natural gas exploration and production operations to incur future capital expenditures in connection with the addition or modification of existing air emission control equipment and strategies. In addition, some oil and natural gas facilities may be included within the categories of hazardous air pollutant sources, which are subject to increasing regulation under CAA. Failure to comply with these requirements could subject a regulated entity to monetary penalties, injunctions, conditions or restrictions on operations, and enforcement actions. Oil and natural gas exploration and production facilities may be required to incur certain capital expenditures in the future for air pollution control equipment in connection with obtaining and maintaining operating permits and approvals for air emissions.

Scientific studies have suggested that emissions of certain gases, commonly referred to as greenhouse gases and including carbon dioxide and methane, may be contributing to warming of the atmosphere. In response to such studies, Congress is considering legislation to reduce emissions of greenhouse gases. In addition, at least 17 states have declined to wait on Congress to develop and implement climate control legislation and have already taken legal measures to reduce emissions of greenhouse gases. Also, as a result of the Supreme Court s decision on April 2, 2007 in *Massachusetts, et al. v. EPA*, the EPA must consider whether it is required to regulate greenhouse gas emissions from mobile sources (e.g., cars and trucks) even if Congress does not adopt new legislation specifically addressing emissions of greenhouse gases. The Supreme Court s holding in *Massachusetts* that greenhouse gases fall under CAA s definition of air pollutant may also result in future regulation of greenhouse gas emissions from stationary sources under various CAA programs, including those used in oil and natural gas exploration and production operations. It is not possible to predict how legislation that may be enacted to address greenhouse gas emissions would impact the oil and natural gas exploration and production business. However, future laws and regulations could result in increased compliance costs or additional operating restrictions and could have a material adverse effect on our business, financial position, demand for our operations, results of operations, and cash flows.

Activities on Federal Lands. Oil and natural gas exploration and production activities on federal lands are subject to the National Environmental Policy Act (NEPA). NEPA requires federal agencies, including the Department of the Interior, to evaluate major agency actions having the potential to significantly impact the environment. In the course of such evaluations, an agency will prepare an Environmental Assessment that assesses the potential direct, indirect, and cumulative impacts of a proposed project and, if necessary, will prepare a more detailed Environmental Impact Statement that may be made available for public review and

ENCORE ACQUISITION COMPANY

comment. Our current exploration and production activities and planned exploration and development activities on federal lands require governmental permits that are subject to the requirements of NEPA. This process has the potential to delay the development of our oil and natural gas projects.

Occupational Safety and Health Act (OSH Act) and Other Laws and Regulation. We are subject to the requirements of OSH Act and comparable state statutes. These laws and the implementing regulations strictly govern the protection of the health and safety of employees. The Occupational Safety and Health Administration s hazard communication standard, EPA community right-to-know regulations under Title III of CERCLA, and similar state statutes require that we organize and/or disclose information about hazardous materials used or produced in our operations. We believe that we are in substantial compliance with these applicable requirements and with other OSH Act and comparable requirements.

We believe that we are in substantial compliance with all existing environmental laws and regulations applicable to our operations and that our continued compliance with existing requirements will not have a material adverse impact on our financial condition and results of operations. We did not incur any material capital expenditures for remediation or pollution control activities during 2009, and, as of the date of this Report, we are not aware of any environmental issues or claims that will require material capital expenditures in the future. However, accidental spills or releases may occur in the course of our operations, and we may incur substantial costs and liabilities as a result of such spills or releases, including those relating to claims for damage to property and persons. Moreover, the passage of more stringent laws or regulations in the future may have a negative impact on our business, financial condition, or results of operations.

Other Regulation of the Oil and Natural Gas Industry

The oil and natural gas industry is extensively regulated by numerous federal, state, and local authorities. Legislation affecting the oil and natural gas industry is under constant review for amendment or expansion, frequently increasing the regulatory burden. Also, numerous departments and agencies, both federal and state, are authorized by statute to issue rules and regulations binding on the oil and natural gas industry and its individual members, some of which carry substantial penalties for failure to comply. Although the regulatory burden on the oil and natural gas industry increases our cost of doing business and, consequently, affects our profitability, these burdens generally do not affect us any differently or to any greater or lesser extent than they affect other companies in the industry with similar types, quantities, and locations of production.

Legislation continues to be introduced in Congress and development of regulations continues in the Department of Homeland Security and other agencies concerning the security of industrial facilities, including oil and natural gas facilities. Our operations may be subject to such laws and regulations. Presently, it is not possible to accurately estimate the costs we could incur to comply with any such facility security laws or regulations, but such expenditures could be substantial.

Development and Production. Our operations are subject to various types of regulation at the federal, state, and local levels. These types of regulation include requiring permits for the development of wells, development bonds, and reports concerning operations. Most states, and some counties and municipalities, in which we operate also regulate one or more of the following:

location of wells;

- methods of developing and casing wells;
- surface use and restoration of properties upon which wells are drilled;
- plugging and abandoning of wells; and
- notification of surface owners and other third parties.

State laws regulate the size and shape of development and spacing units or proration units governing the pooling of oil and natural gas properties. Some states allow forced pooling or integration of tracts in order to

ENCORE ACQUISITION COMPANY

facilitate exploitation while other states rely on voluntary pooling of lands and leases. In some instances, forced pooling or unitization may be implemented by third parties and may reduce our interest in the unitized properties. In addition, state conservation laws establish maximum rates of production from oil and natural gas wells, generally prohibit the venting or flaring of natural gas, and impose requirements regarding the ratability of production. These laws and regulations may limit the amount of oil and natural gas we can produce from our wells or limit the number of wells or the locations at which we can drill. Moreover, each state generally imposes a production or severance tax with respect to the production and sale of oil, natural gas, and NGLs within its jurisdiction.

Natural Gas Gathering. Section 1(b) of the Natural Gas Act (NGA), exempts natural gas gathering facilities from the jurisdiction of the Federal Energy Regulatory Commission (the FERC). ENP owns a number of facilities that it believes would meet the traditional tests the FERC has used to establish a pipeline s status as a gatherer not subject to the FERC s jurisdiction. In the states in which ENP operates, regulation of gathering facilities and intrastate pipeline facilities generally includes various safety, environmental, and in some circumstances, nondiscriminatory take requirement and complaint-based rate regulation.

Natural gas gathering may receive greater regulatory scrutiny at both the state and federal levels since the FERC has taken a less stringent approach to regulation of the offshore gathering activities of interstate pipeline transmission companies and a number of such companies have transferred gathering facilities to unregulated affiliates. Our gathering operations could be adversely affected should they become subject to the application of state or federal regulation of rates and services. Our gathering operations also may be or become subject to safety and operational regulations relating to the design, installation, testing, construction, operation, replacement, and management of gathering facilities. Additional rules and legislation pertaining to these matters are considered or adopted from time to time. We cannot predict what effect, if any, such changes might have on our operations, but the industry could be required to incur additional capital expenditures and increased costs depending on future legislative and regulatory changes.

Sales of Natural Gas. The price at which we buy and sell natural gas is not subject to federal regulation and, for the most part, is not subject to state regulation. Our sales of natural gas are affected by the availability, terms, and cost of pipeline transportation. The price and terms of access to pipeline transportation are subject to extensive federal and state regulation. The FERC is continually proposing and implementing new rules and regulations affecting those segments of the natural gas industry, most notably interstate natural gas transmission companies that remain subject to the FERC s jurisdiction. These initiatives also may affect the intrastate transportation of natural gas under certain circumstances. The stated purpose of many of these regulatory changes is to promote competition among the various sectors of the natural gas industry, and these initiatives generally reflect more light-handed regulation. We cannot predict the ultimate impact of these regulatory changes on our natural gas marketing operations, and we note that some of the FERC s more recent proposals may adversely affect the availability and reliability of interruptible transportation service on interstate pipelines. We do not believe that we will be affected by any such FERC action materially differently than other natural gas marketers with which we compete.

The Energy Policy Act of 2005 (EP Act 2005) gave the FERC increased oversight and penalty authority regarding market manipulation and enforcement. EP Act 2005 amended NGA to prohibit market manipulation and also amended NGA and the Natural Gas Policy Act of 1978 (NGPA) to increase civil and criminal penalties for any violations of NGA, NGPA, and any rules, regulations, or orders of the FERC to up to $1,000,000 per day, per violation. In 2006, the FERC issued a rule regarding market manipulation, which makes it unlawful for any entity, in connection with the purchase or sale of natural gas or transportation service subject to the FERC s jurisdiction, to defraud, make an untrue statement, or omit a material fact, or engage in any practice, act, or course of business that operates or would operate as a fraud. This rule works together with the FERC s enhanced penalty authority to provide increased oversight of the natural gas marketplace.

ENCORE ACQUISITION COMPANY

State Regulation. The various states regulate the development, production, gathering, and sale of oil and natural gas, including imposing severance taxes and requirements for obtaining drilling permits. Reduced rates or credits may apply to certain types of wells and production methods.

In addition to production taxes, Texas and Montana each impose ad valorem taxes on oil and natural gas properties and production equipment. Wyoming and New Mexico impose an ad valorem tax on the gross value of oil and natural gas production in lieu of an ad valorem tax on the underlying oil and natural gas properties. Wyoming also imposes an ad valorem tax on production equipment. North Dakota imposes an ad valorem tax on gross oil and natural gas production in lieu of an ad valorem tax on the underlying oil and gas leases or on production equipment used on oil and gas leases.

States also regulate the method of developing new fields, the spacing and operation of wells, and the prevention of waste of oil and natural gas resources. States may regulate rates of production and establish maximum daily production allowables from oil and natural gas wells based on market demand or resource conservation, or both. States do not regulate wellhead prices or engage in other similar direct economic regulation, but they may do so in the future. The effect of these regulations may be to limit the amounts of oil and natural gas that may be produced from our wells, and to limit the number of wells or locations we can drill.

Federal, State, or Native American Leases. Our operations on federal, state, or Native American oil and natural gas leases are subject to numerous restrictions, including nondiscrimination statutes. Such operations must be conducted pursuant to certain on-site security regulations and other permits and authorizations issued by the Federal Bureau of Land Management, Minerals Management Service, and other agencies.

Operating Hazards and Insurance

The oil and natural gas business involves a variety of operating risks, including fires, explosions, blowouts, environmental hazards, and other potential events that can adversely affect our ability to conduct operations and cause us to incur substantial losses. Such losses could reduce or eliminate the funds available for exploration, exploitation, or leasehold acquisitions or result in loss of properties.

In accordance with industry practice, we maintain insurance against some, but not all, potential risks and losses. We do not carry business interruption insurance. We may not obtain insurance for certain risks if we believe the cost of available insurance is excessive relative to the risks presented. In addition, pollution and environmental risks generally are not fully insurable at a reasonable cost. If a significant accident or other event occurs that is not fully covered by insurance, it could adversely affect us.

Employees

As of December 31, 2009, we had a staff of 421 persons, including 35 engineers, 18 geologists, and 13 landmen, none of which are represented by labor unions or covered by any collective bargaining agreement. We believe that relations with our employees are satisfactory.

Principal Executive Office

Our principal executive office is located at 777 Main Street, Suite 1400, Fort Worth, Texas 76102. Our main telephone number is (817) 877-9955.

Available Information

We make available electronically, free of charge through our website (www.encoreacq.com), our annual reports on Form 10-K, quarterly reports on Form 10-Q, current reports on Form 8-K, and other filings with the SEC pursuant to Section 13(a) of the Securities Exchange Act of 1934 (the Exchange Act) as soon as reasonably practicable after we electronically file such material with, or furnish such material, to the SEC. In addition, you may read and copy any materials that we file with the SEC at its public reference room at

Table of Contents

ENCORE ACQUISITION COMPANY

100 F Street, N.E., Room 1580, Washington, D.C. 20549. Information concerning the operation of the public reference room may be obtained by calling the SEC at 1-800-SEC-0330. The SEC also maintains a website (www.sec.gov) that contains reports, proxy statements, and other information regarding issuers, like us, that file electronically with the SEC.

We have adopted a code of business conduct and ethics that applies to all directors, officers, and employees, including our principal executive officer and principal financial officer. The code of business conduct and ethics is available on our website. In the event that we make changes in, or provide waivers from, the provisions of this code of business conduct and ethics that the SEC or the NYSE require us to disclose, we intend to disclose these events on our website.

Our Board has four standing committees: (1) audit; (2) compensation; (3) nominating and corporate governance; and (4) special stock award. Our Board committee charters, code of business conduct and ethics, and corporate governance guidelines are available on our website.

The information on our website or any other website is not incorporated by reference into this Report.

Table of Contents

ENCORE ACQUISITION COMPANY

ITEM 1A. *RISK FACTORS*

You should carefully consider each of the following risks and all of the information provided elsewhere in this Report. If any of the risks described below or elsewhere in this Report were actually to occur, our business, financial condition, results of operations, or cash flows could be materially and adversely affected. In that case, we may be unable to pay interest on, or the principal of, our debt securities, the trading price of our common stock could decline, and you could lose all or part of your investment.

Failure to complete the Merger or delays in completing the Merger could negatively affect our stock price and future business and operations.

There is no assurance that we will be able to consummate the Merger. If the Merger is not completed for any reason, we may be subject to a number of risks, including the following:

- we will not realize the benefits expected from the Merger, including a potentially enhanced financial and competitive position;

- the current market price of our common stock may reflect a market assumption that the Merger will occur and a failure to complete the Merger could result in a negative perception by the stock market of us generally and a resulting decline in the market price of our common stock; and

- certain costs relating to the Merger, including certain investment banking, financing, legal, and accounting fees and expenses, must be paid even if the Merger is not completed, and we may be required to pay substantial fees to Denbury if the Merger Agreement is terminated under specified circumstances.

Delays in completing the Merger could exacerbate uncertainties concerning the effect of the Merger, which may have an adverse effect on the business following the Merger and could defer or detract from the realization of the benefits expected to result from the Merger.

There may be substantial disruption to our business and distraction of our management and employees as a result of the Merger.

There may be substantial disruption to our business and distraction of our management and employees from day-to-day operations because matters related to the Merger may require substantial commitments of time and resources, which could otherwise have been devoted to other opportunities that could have been beneficial to us.

Business uncertainties and contractual restrictions while the Merger is pending may have an adverse effect on us.

Uncertainty about the effect of the Merger on employees, suppliers, partners, regulators, and customers may have an adverse effect on us. These uncertainties may impair our ability to attract, retain, and motivate key personnel until the Merger is consummated and could cause suppliers, customers, and others that deal with us to defer purchases or other decisions concerning us or seek to change existing business relationships with us. In addition, the Merger Agreement restricts us from making certain acquisitions and taking other specified actions without Denbury s approval. These restrictions could prevent us from pursuing attractive business opportunities that may arise prior to the completion of the Merger.

Our oil and natural gas reserves naturally decline and the failure to replace our reserves could adversely affect our financial condition.

Because our oil and natural gas properties are a depleting asset, our future oil and natural gas reserves, production volumes, and cash flows depend on our success in developing and exploiting our current reserves efficiently and finding or acquiring additional recoverable reserves economically. We may not be able to

ENCORE ACQUISITION COMPANY

develop, find, or acquire additional reserves to replace our current and future production at acceptable costs, which would adversely affect our business, financial condition, and results of operations.

We need to make substantial capital expenditures to maintain and grow our asset base. If lower oil and natural gas prices or operating difficulties result in our cash flows from operations being less than expected or limit our ability to borrow under our revolving credit facility, we may be unable to expend the capital necessary to find, develop, or acquire additional reserves.

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

The oil and natural gas markets are very volatile, and we cannot accurately predict future oil and natural gas prices. Prices for oil and natural gas may fluctuate widely in response to relatively minor changes in the supply of and demand for oil and natural gas, market uncertainty, and a variety of additional factors that are beyond our control, such as:

- overall domestic and global economic conditions;
- weather conditions;
- political and economic conditions in oil and natural gas producing countries, including those in the Middle East, Africa, and South America;
- actions of the Organization of Petroleum Exporting Countries and state-controlled oil companies relating to oil price and production controls;
- the impact of U.S. dollar exchange rates on oil and natural gas prices;
- technological advances affecting energy consumption and energy supply;
- domestic and foreign governmental regulations and taxation;
- the impact of energy conservation efforts;
- the proximity, capacity, cost, and availability of oil and natural gas pipelines and other transportation facilities;
- the availability of refining capacity; and
- the price and availability of alternative fuels.

The worldwide financial and credit crisis has reduced the availability of liquidity and credit to fund the continuation and expansion of industrial business operations worldwide. The shortage of liquidity and credit combined with substantial losses in worldwide equity markets led to an extended worldwide economic slowdown in 2008 and 2009, which is expected to continue into 2010. The slowdown in economic activity has reduced worldwide demand for energy and resulted in lower oil and natural gas prices.

Our revenue, profitability, and cash flow depend upon the prices of and demand for oil and natural gas, and a drop in prices can significantly affect our financial results and impede our growth. In particular, declines in commodity prices will:

- negatively impact the value of our reserves, because declines in oil and natural gas prices would reduce the amount of oil and natural gas that we can produce economically;
- reduce the amount of cash flow available for capital expenditures, repayment of indebtedness, and other corporate purposes; and
- result in a decrease in the borrowing base under our revolving credit facility or otherwise limit our ability to borrow money or raise additional capital.

ENCORE ACQUISITION COMPANY

An increase in the differential between benchmark prices of oil and natural gas and the wellhead price we receive could adversely affect our financial condition, results of operations, and cash flows.

The prices that we receive for our oil and natural gas production sometimes trade at a discount to the relevant benchmark prices, such as NYMEX. The difference between the benchmark price and the price we receive is called a differential. We cannot accurately predict oil and natural gas differentials. For example, the oil production from our Elk Basin assets has historically sold at a higher discount to NYMEX as compared to our Permian Basin assets due to competition from Canadian and Rocky Mountain producers, in conjunction with limited refining and pipeline capacity from the Rocky Mountain area, and corresponding deep pricing discounts by regional refiners. Increases in differentials could significantly reduce our cash available for development of our properties and adversely affect our financial condition, results of operations, and cash flows.

Price declines may result in a write-down of our asset carrying values, which could have a material adverse effect on our results of operations and limit our ability to borrow funds under our revolving credit facility.

Declines in oil and natural gas prices may result in our having to make substantial downward revisions to our estimated reserves. If this occurs, or if our estimates of development costs increase, production data factors change, or development results deteriorate, accounting rules may require us to write down, as a non-cash charge to earnings, the carrying value of our oil and natural gas properties and goodwill. If we incur such impairment charges, it could have a material adverse effect on our results of operations in the period incurred and on our ability to borrow funds under our revolving credit facility. In addition, any write-downs that result in a reduction in our borrowing base could require prepayments of indebtedness under our revolving credit facility.

Our commodity derivative contract activities could result in financial losses or could reduce our income and cash flows. Furthermore, in the future, our commodity derivative contract positions may not adequately protect us from changes in commodity prices.

To reduce our exposure to fluctuations in the price of oil and natural gas, we enter into derivative arrangements for a significant portion of our forecasted oil and natural gas production. The extent of our commodity price exposure is related largely to the effectiveness and scope of our derivative activities, as well as to the ability of counterparties under our commodity derivative contracts to satisfy their obligations to us. For example, the derivative instruments we utilize are based on posted market prices, which may differ significantly from the actual prices we realize on our production. Changes in oil and natural gas prices could result in losses under our commodity derivative contracts.

Our actual future production may be significantly higher or lower than we estimate at the time we enter into derivative transactions for such period. If the actual amount is higher than we estimate, we will have greater commodity price exposure than we intended. If the actual amount is lower than the notional amount of our derivative financial instruments, we might be forced to satisfy all or a portion of our derivative transactions without the benefit of the cash flow from the sale of the underlying physical commodity, resulting in a substantial diminution of our liquidity. As a result of these factors, our derivative activities may not be as effective as we intend in reducing the volatility of our cash flows, and in certain circumstances may actually increase the volatility of our cash flows. In addition, our derivative activities are subject to the following risks:

- a counterparty may not perform its obligation under the applicable derivative instrument, which risk may have been exacerbated by the worldwide financial and credit crisis; and there may be a change in the expected differential between the underlying commodity price in the derivative instrument and the actual price received, which may result in payments to our derivative counterparty that are not accompanied by our receipt of higher prices from our production in the field.

ENCORE ACQUISITION COMPANY

In addition, certain commodity derivative contracts that we may enter into may limit our ability to realize additional revenues from increases in the prices for oil and natural gas.

We have oil and natural gas commodity derivative contracts covering a significant portion of our forecasted production for 2010. These contracts are intended to reduce our exposure to fluctuations in the price of oil and natural gas. We have a much smaller commodity derivative contract portfolio covering our forecasted production in 2011 and 2012. After 2010, and unless we enter into new commodity derivative contracts, our exposure to oil and natural gas price volatility will increase significantly each year as our commodity derivative contracts expire. We may not be able to obtain additional commodity derivative contracts on acceptable terms, if at all. Our failure to mitigate our exposure to commodity price volatility through commodity derivative contracts could have a negative effect on our financial condition and results of operation and significantly reduce our cash flows.

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

As of December 31, 2009, we were entitled to future payments of approximately $61.0 million from counterparties under our commodity derivative contracts. The worldwide financial and credit crisis may have adversely affected the ability of these counterparties to fulfill their obligations to us. If one or more of our counterparties is unable or unwilling to make required payments to us under our commodity derivative contracts, it could have a material adverse effect on our financial condition and results of operations.

Our estimated proved reserves are based on many assumptions that may prove to be inaccurate. Any material inaccuracies in these reserve estimates or underlying assumptions will materially affect the quantities and present value of our reserves.

It is not possible to measure underground accumulations of oil or natural gas in an exact way. In estimating our oil and natural gas reserves, we and our independent reserve engineers make certain assumptions that may prove to be incorrect, including assumptions relating to oil and natural gas prices, production levels, capital expenditures, operating and development costs, the effects of regulation, and availability of funds. If these assumptions prove to be incorrect, our estimates of reserves, the economically recoverable quantities of oil and natural gas attributable to any particular group of properties, the classification of reserves based on risk of recovery, and our estimates of the future net cash flows from our reserves could change significantly.

Our Standardized Measure is calculated using prices and costs in effect as of the date of estimation, less future development, production, net abandonment, and income tax expenses, and discounted at 10 percent per annum to reflect the timing of future net revenue in accordance with the rules and regulations of the SEC. The Standardized Measure of our estimated proved reserves is not necessarily the same as the current market value of our estimated proved reserves. We base the estimated discounted future net cash flows from our estimated proved reserves on prices and costs in effect on the day of estimate. Over time, we may make material changes to reserve estimates to take into account changes in our assumptions and the results of actual development and production.

The reserve estimates we make for fields that do not have a lengthy production history are less reliable than estimates for fields with lengthy production histories. A lack of production history may contribute to inaccuracy in our estimates of proved reserves, future production rates, and the timing of development expenditures.

The timing of both our production and our incurrence of expenses in connection with the development, production, and abandonment of oil and natural gas properties will affect the timing of actual future net cash flows from proved reserves, and thus their actual present value. In addition, the 10 percent discount factor we use when calculating discounted future net cash flows may not be the most appropriate discount factor based

Table of Contents

ENCORE ACQUISITION COMPANY

on interest rates in effect from time to time and risks associated with us or the oil and natural gas industry in general.

Developing and producing oil and natural gas are costly and high-risk activities with many uncertainties that could adversely affect our financial condition or results of operations.

The cost of developing, completing, and operating a well is often uncertain, and cost factors can adversely affect the economics of a well. If commodity prices decline, the cost of developing, completing and operating a well may not decline in proportion to the prices that we receive for our production, resulting in higher operating and capital costs as a percentage of oil and natural gas revenues. Our efforts will be uneconomical if we drill dry holes or wells that are productive but do not produce as much oil and natural gas as we had estimated. Furthermore, our development and production operations may be curtailed, delayed, or canceled as a result of other factors, including:

- higher costs, shortages, or delivery delays of rigs, equipment, labor, or other services;
- unexpected operational events and/or conditions;
- reductions in oil and natural gas prices;
- increases in severance taxes;
- limitations in the market for oil and natural gas;
- adverse weather conditions and natural disasters;
- facility or equipment malfunctions, and equipment failures or accidents;
- title problems;
- pipe or cement failures and casing collapses;
- compliance with environmental and other governmental requirements;
- environmental hazards, such as natural gas leaks, oil spills, pipeline ruptures, and discharges of toxic gases;
- lost or damaged oilfield development and service tools;
- unusual or unexpected geological formations, and pressure or irregularities in formations;
- loss of drilling fluid circulation;
- fires, blowouts, surface craterings, and explosions;
- uncontrollable flows of oil, natural gas, or well fluids; and
- loss of leases due to incorrect payment of royalties.

If any of these factors were to occur with respect to a particular field, we could lose all or a part of our investment in the field, or we could fail to realize the expected benefits from the field, either of which could materially and adversely affect our revenue and profitability.

Secondary and tertiary recovery techniques may not be successful, which could adversely affect our financial condition or results of operations.

A significant portion of our production and reserves rely on secondary and tertiary recovery techniques. If production response is less than forecasted for a particular project, then the project may be uneconomic or

ENCORE ACQUISITION COMPANY

generate less cash flow and reserves than we had estimated prior to investing capital. Risks associated with secondary and tertiary recovery techniques include, but are not limited to, the following:

- lower than expected production;
- longer response times;
- higher operating and capital costs;
- shortages of equipment; and
- lack of technical expertise.

If any of these risks occur, it could adversely affect our financial condition or results of operations.

Shortages of rigs, equipment, and crews could delay our operations.

Higher oil and natural gas prices generally increase the demand for rigs, equipment, and crews and can lead to shortages of, and increasing costs for, development equipment, services, and personnel. Shortages of, or increasing costs for, experienced development crews and oil field equipment and services could restrict our ability to drill the wells and conduct the operations that we have planned. Any delay in the development of new wells or a significant increase in development costs could reduce our revenues.

If we do not make acquisitions, our future growth could be limited.

Acquisitions are an essential part of our growth strategy, and our ability to acquire additional properties on favorable terms is important to our long-term growth. We may be unable to make acquisitions because we are:

- unable to identify attractive acquisition candidates or negotiate acceptable purchase contracts with them;
- unable to obtain financing for these acquisitions on economically acceptable terms; or
- outbid by competitors.

Competition for acquisitions is intense and may increase the cost of, or cause us to refrain from, completing acquisitions. If we are unable to acquire properties with proved reserves, our total proved reserves could decline as a result of our production. Future acquisitions could result in our incurring additional debt, contingent liabilities, and expenses, all of which could have a material adverse effect on our financial condition and results of operations. Furthermore, our financial position and results of operations may fluctuate significantly from period to period based on whether significant acquisitions are completed in particular periods.

Any acquisitions we complete are subject to substantial risks that could adversely affect our financial condition and results of operations.

Any acquisition involves potential risks, including, among other things:

the validity of our assumptions about reserves, future production, revenues, capital expenditures, and operating costs, including synergies;

an inability to integrate the businesses we acquire successfully;

a decrease in our liquidity by using a significant portion of our available cash or borrowing capacity under our revolving credit facility to finance acquisitions;

a significant increase in our interest expense or financial leverage if we incur additional debt to finance acquisitions;

Table of Contents

ENCORE ACQUISITION COMPANY

the assumption of unknown liabilities, losses, or costs for which we are not indemnified or for which our indemnity is inadequate;

the diversion of management s attention from other business concerns;

an inability to hire, train, or retain qualified personnel to manage and operate our growing business and assets;

natural disasters;

the incurrence of other significant charges, such as impairment of oil and natural gas properties, goodwill, or other intangible assets, asset devaluation, or restructuring charges;

unforeseen difficulties encountered in operating in new geographic areas; and

customer or key employee losses at the acquired businesses.

Our decision to acquire a property will depend in part on the evaluation of data obtained from production reports and engineering studies, geophysical and geological analyses, and seismic and other information, the results of which are often inconclusive and subject to various interpretations.

Also, our reviews of acquired properties are inherently incomplete because it generally is not feasible to perform an in-depth review of the individual properties involved in each acquisition given time constraints imposed by sellers. Even a detailed review of records and properties may not necessarily reveal existing or potential problems, nor will it permit a buyer to become sufficiently familiar with the properties to fully assess their deficiencies and potential. Inspections may not always be performed on every well, and environmental problems, such as groundwater contamination, are not necessarily observable even when an inspection is undertaken.

A substantial portion of our producing properties is located in one geographic area and adverse developments in any of our operating areas would negatively affect our financial condition and results of operations.

We have extensive operations in the CCA. Our CCA properties represented approximately 32 percent of our proved reserves as of December 31, 2009 and accounted for 25 percent of our 2009 production. Any circumstance or event that negatively impacts production or marketing of oil and natural gas in the CCA would materially affect our results of operations and cash flows.

We depend on certain customers for a substantial portion of our sales. If these customers reduce the volumes of oil and natural gas they purchase from us, our revenues and cash available for distribution will decline to the extent we are not able to find new customers for our production.

For 2009, our largest purchaser was Eighty-Eight Oil, which accounted for 18 percent of our total sales of production. If customer, or any other significant customer, were to reduce the production purchased from us, our revenue and cash available for distribution will decline to the extent we are not able to find new customers for our production.

Competition in the oil and natural gas industry is intense and many of our competitors have greater resources than we do. As a result, we may be unable to effectively compete with larger competitors.

The oil and natural gas industry is intensely competitive with respect to acquiring prospects and productive properties, marketing oil and natural gas, and securing equipment and trained personnel, and we compete with other companies that have greater resources. Many of our competitors are major and large independent oil and natural gas companies, and possess financial, technical, and personnel resources substantially greater than us. Those companies may be able to develop and acquire more prospects and productive properties than our resources permit. Our ability to acquire additional properties and to discover reserves in

Table of Contents

ENCORE ACQUISITION COMPANY

the future will depend on our ability to evaluate and select suitable properties and to consummate transactions in a highly competitive environment. Some of our competitors not only drill for and produce oil and natural gas but also carry on refining operations and market petroleum and other products on a regional, national, or worldwide basis. These companies may be able to pay more for oil and natural gas properties and evaluate, bid for, and purchase a greater number of properties than our resources permit. In addition, there is substantial competition for investment capital in the oil and natural gas industry. These companies may have a greater ability to continue development activities during periods of low oil and natural gas prices and to absorb the burden of present and future federal, state, local, and other laws and regulations. Our inability to compete effectively could have a material adverse impact on our business activities, financial condition, and results of operations.

We have significant indebtedness and may incur significant additional indebtedness, which could negatively impact our financial condition, results of operations, and business prospects.

As of December 31, 2009, we had total consolidated debt of $1.2 billion and $889.7 million of consolidated available borrowing capacity under our revolving credit facilities. We have the ability to incur additional debt under our revolving credit facilities, subject to borrowing base limitations. Our future indebtedness could have important consequences to us, including:

- our ability to obtain additional financing, if necessary, for working capital, capital expenditures, acquisitions, or other purposes may not be available on favorable terms, if at all;
- covenants contained in future debt arrangements may require us to meet financial tests that may affect our flexibility in planning for and reacting to changes in our business, including possible acquisition opportunities;
- we will need a substantial portion of our cash flow to make principal and interest payments on our indebtedness, reducing the funds that would otherwise be available for operations and future business opportunities; and
- our debt level will make us more vulnerable to competitive pressures, or a downturn in our business or the economy in general, than our competitors with less debt.

Our ability to service our indebtedness depends upon, among other things, our future financial and operating performance, which is affected by prevailing economic conditions and financial, business, regulatory, and other factors, some of which are beyond our control. If our operating results are not sufficient to service our indebtedness, we will be forced to take actions such as reducing or delaying business activities, acquisitions, investments and/or capital expenditures, selling assets, restructuring or refinancing our indebtedness, or seeking additional equity capital or bankruptcy protection. We may not be able to affect any of these remedies on satisfactory terms or at all.

In addition, we are not currently permitted to offset the value of our commodity derivative contracts with a counterparty against amounts that may be owing to such counterparty under our revolving credit facilities.

We are unable to predict the impact of the recent downturn in the credit markets and the resulting costs or constraints in obtaining financing on our business and financial results.

U.S. and global credit and equity markets have recently undergone significant disruption, making it difficult for many businesses to obtain financing on acceptable terms. In addition, equity markets are continuing to experience wide fluctuations in value. If these conditions continue or worsen, our cost of borrowing may increase, and it may be more difficult to obtain financing in the future. In addition, an increasing number of financial institutions have reported significant deterioration in their financial condition. If any of the financial institutions are unable to perform their obligations under our revolving credit agreements and other contracts, and we are unable to find suitable replacements on acceptable terms, our results of operations, liquidity, and cash flows could be adversely affected. We also face challenges relating to the

ENCORE ACQUISITION COMPANY

impact of the disruption in the global financial markets on other parties with which we do business, such as customers and suppliers. The inability of these parties to obtain financing on acceptable terms could impair their ability to perform under their agreements with us and lead to various negative effects on us, including business disruption, decreased revenues, and increases in bad debt write-offs. A sustained decline in the financial stability of these parties could have an adverse impact on our business, results of operations, and liquidity.

Our revolving credit facilities have substantial restrictions and financial covenants that may restrict our business and financing activities.

The operating and financial restrictions and covenants in our revolving credit facilities and any future financing agreements may restrict our ability to finance future operations or capital needs or to engage, expand, or pursue our business activities.

Our ability to comply with the restrictions and covenants in our revolving credit facilities in the future is uncertain and will be affected by the levels of cash flow from our operations and events or circumstances beyond our control. If market or other economic conditions deteriorate, our ability to comply with these covenants may be impaired. If we violate any of the restrictions, covenants, or financial ratios in our revolving credit facilities, a significant portion of our indebtedness may become immediately due and payable and our lenders commitment to make further loans to us may terminate. We might not have, or be able to obtain, sufficient funds to make these accelerated payments. In addition, obligations under our revolving credit facilities are secured by substantially all of our assets, and if we are unable to repay our indebtedness under our revolving credit facilities, the lenders could seek to foreclose on our assets.

Our revolving credit facilities limit the amounts we can borrow to a borrowing base amount, determined by the lenders in their sole discretion. Outstanding borrowings in excess of the borrowing base will be required to be repaid immediately, or we will be required to pledge other oil and natural gas properties as additional collateral.

Our operations are subject to operational hazards and unforeseen interruptions for which we may not be adequately insured.

There are a variety of operating risks inherent in our wells, gathering systems, pipelines, and other facilities, such as leaks, explosions, mechanical problems, and natural disasters, all of which could cause substantial financial losses. Any of these or other similar occurrences could result in the disruption of our operations, substantial repair costs, personal injury or loss of human life, significant damage to property, environmental pollution, impairment of our operations, and substantial revenue losses. The location of our wells, gathering systems, pipelines, and other facilities near populated areas, including residential areas, commercial business centers, and industrial sites, could significantly increase the level of damages resulting from these risks.

We are not fully insured against all risks, including development and completion risks that are generally not recoverable from third parties or insurance. In addition, pollution and environmental risks generally are not fully insurable. Additionally, we may elect not to obtain insurance if we believe that the cost of available insurance is excessive relative to the perceived risks presented. Losses could, therefore, occur for uninsurable or uninsured risks or in amounts in excess of existing insurance coverage. Moreover, insurance may not be available in the future at commercially reasonable costs and on commercially reasonable terms. Changes in the insurance markets due to weather and adverse economic conditions have made it more difficult for us to obtain certain types of coverage. We may not be able to obtain the levels or types of insurance we would otherwise have obtained prior to these market changes, and our insurance may contain large deductibles or fail to cover certain hazards or cover all potential losses. Losses and liabilities from uninsured and underinsured events and delay in the payment of insurance proceeds could have a material adverse effect on our business, financial condition, and results of operations.

Table of Contents

ENCORE ACQUISITION COMPANY

Our business depends in part on gathering and transportation facilities owned by others. Any limitation in the availability of those facilities could interfere with our ability to market our oil and natural gas production and could harm our business.

The marketability of our oil and natural gas production depends in part on the availability, proximity, and capacity of pipelines, oil and natural gas gathering systems, and processing facilities. The amount of oil and natural gas that can be produced and sold is subject to curtailment in certain circumstances, such as pipeline interruptions due to scheduled and unscheduled maintenance, excessive pressure, physical damage, or lack of available capacity on such systems. The curtailments arising from these and similar circumstances may last from a few days to several months. In many cases, we are provided only with limited, if any, notice as to when these circumstances will arise and their duration. Any significant curtailment in gathering system or pipeline capacity could reduce our ability to market our oil and natural gas production and harm our business.

We have limited control over the activities on properties we do not operate.

Other companies operated approximately 21 percent of our properties (measured by total reserves) and approximately 44 percent of our wells as of December 31, 2009. We have limited ability to influence or control the operation or future development of these non-operated properties or the amount of capital expenditures that we are required to fund with respect to them. Our dependence on the operator and other working interest owners for these projects and our limited ability to influence or control the operation and future development of these properties could materially adversely affect the realization of our targeted returns on capital in development or acquisition activities and lead to unexpected future costs.

We are subject to complex federal, state, local, and other laws and regulations that could adversely affect the cost, manner, or feasibility of conducting our operations.

Our oil and natural gas exploration and production operations are subject to complex and stringent laws and regulations. Environmental and other governmental laws and regulations have increased the costs to plan, design, drill, install, operate, and abandon oil and natural gas wells and related pipeline and processing facilities. In order to conduct our operations in compliance with these laws and regulations, we must obtain and maintain numerous permits, approvals, and certificates from various federal, state, and local governmental authorities. We may incur substantial costs in order to maintain compliance with these existing laws and regulations. In addition, our costs of compliance may increase if existing laws and regulations are revised or reinterpreted, or if new laws and regulations become applicable to our operations.

Our business is subject to federal, state, and local laws and regulations as interpreted and enforced by governmental authorities possessing jurisdiction over various aspects of the exploration for, and production of, oil and natural gas. Failure to comply with such laws and regulations, as interpreted and enforced, could have a material adverse effect on our business, financial condition, and results of operations. Please read Items 1 and 2. Business and Properties Environmental Matters and Regulation and Items 1 and 2. Business and Properties Other Regulation of the Oil and Natural Gas Industry for a description of the laws and regulations that affect us.

Possible regulations related to global warming and climate change could have an adverse effect on our operations and the demand for oil and natural gas.

Recent scientific studies have suggested that emissions of certain gases, commonly referred to as greenhouse gases, may be contributing to the warming of the Earth s atmosphere. Methane, a primary component of natural gas, and carbon dioxide, a byproduct of the burning of refined oil products and natural gas, are examples of greenhouse gases. The U.S. Congress is considering climate-related legislation to reduce emissions of greenhouse gases. In addition, at least 20 states have developed measures to regulate emissions of greenhouse gases, primarily through the planned development of greenhouse gas emissions inventories and/or regional greenhouse gas cap and trade programs. The EPA has adopted regulations requiring reporting of greenhouse gas emissions from certain facilities and is considering additional regulation of greenhouse gases as air pollutants under the CAA. Passage of climate change legislation or other regulatory initiatives by

ENCORE ACQUISITION COMPANY

Congress or various states, or the adoption of regulations by the EPA or analogous state agencies, that regulate or restrict emissions of greenhouse gases (including methane or carbon dioxide) in areas in which we conduct business could have an adverse effect our operations and the demand for oil and natural gas.

Our operations expose us to significant costs and liabilities with respect to environmental and operational safety matters.

We may incur significant costs and liabilities as a result of environmental and safety requirements applicable to our oil and natural gas production activities. In addition, we often indemnify sellers of oil and natural gas properties for environmental liabilities they or their predecessors may have created. These costs and liabilities could arise under a wide range of federal, state, and local environmental and safety laws and regulations, which have become increasingly strict over time. Failure to comply with these laws and regulations may result in the assessment of administrative, civil, and criminal penalties, imposition of cleanup and site restoration costs, liens and, to a lesser extent, issuance of injunctions to limit or cease operations. In addition, claims for damages to persons or property may result from environmental and other impacts of our operations.

Strict, joint, and several liability may be imposed under certain environmental laws, which could cause us to become liable for the conduct of others or for consequences of our own actions that were in compliance with all applicable laws at the time those actions were taken. New laws, regulations, or enforcement policies could be more stringent and impose unforeseen liabilities or significantly increase compliance costs. If we are not able to recover the resulting costs through insurance or increased revenues, our profitability could be adversely affected.

Our development and exploratory drilling efforts may not be profitable or achieve our targeted returns.

Development and exploratory drilling and production activities are subject to many risks, including the risk that we will not discover commercially productive oil or natural gas reserves. In order to further our development efforts, we acquire both producing and unproved properties as well as lease undeveloped acreage that we believe will enhance our growth potential and increase our earnings over time. However, we cannot assure you that all prospects will be economically viable or that we will not be required to impair our initial investments.

In addition, there can be no assurance that unproved property acquired by us or undeveloped acreage leased by us will be profitably developed, that new wells drilled by us will be productive, or that we will recover all or any portion of our investment in such unproved property or wells. The costs of drilling and completing wells are often uncertain, and drilling operations may be curtailed, delayed, or canceled as a result of a variety of factors, including unexpected drilling conditions, pressure or irregularities in formations, equipment failures or accidents, weather conditions, and shortages or delays in the delivery of equipment. Drilling for oil and natural gas may involve unprofitable efforts, not only from dry holes, but also from wells that are productive but do not produce sufficient commercial quantities to cover the development, operating, and other costs. In addition, wells that are profitable may not meet our internal return targets, which are dependent upon the current and future market prices for oil and natural gas, costs associated with producing oil and natural gas, and our ability to add reserves at an acceptable cost.

Seismic technology does not allow us to obtain conclusive evidence that oil or natural gas reserves are present or economically producible prior to spudding a well. We rely to a significant extent on seismic data and other advanced technologies in identifying unproved property prospects and in conducting our exploration activities. The use of seismic data and other technologies also requires greater up-front costs than development on proved properties.

Our development, exploitation, and exploration operations require substantial capital, and we may be unable to obtain needed financing on satisfactory terms.

We make and will continue to make substantial capital expenditures in development, exploitation, and exploration projects. We intend to finance these capital expenditures through operating cash flows. However,

ENCORE ACQUISITION COMPANY

additional financing sources may be required in the future to fund our capital expenditures. Financing may not continue to be available under existing or new financing arrangements, or on acceptable terms, if at all. If additional capital resources are not available, we may be forced to curtail our development and other activities or be forced to sell some of our assets on an untimely or unfavorable basis.

The loss of key personnel could adversely affect our business.

Our development success and the success of other activities integral to our operations will depend, in part, on our ability to attract and retain experienced geologists, engineers, and other professionals. Competition for experienced geologists, engineers, and other professionals is extremely intense and the cost of attracting and retaining technical personnel has increased significantly in recent years. If we cannot retain our technical personnel or attract additional experienced technical personnel, our ability to compete could be harmed. Furthermore, escalating personnel costs could adversely affect our results of operations and financial condition.

ITEM 1B. *UNRESOLVED STAFF COMMENTS*

There were no unresolved SEC staff comments as of December 31, 2009.

ITEM 3. *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.

Litigation Related to the Merger

Three shareholder lawsuits styled as class actions have been filed against us and our Board related to the Merger. The lawsuits are entitled:

(1) *Sanjay Israni, Individually and On Behalf of All Others Similarly Situated vs. Encore Acquisition Company et al.* (filed November 4, 2009 in the District Court of Tarrant County, Texas);

(2) *Teamsters Allied Benefit Funds, Individually and On Behalf of All Others Similarly Situated vs. Encore Acquisition Company et al.* (filed November 5, 2009 in the Court of Chancery in the State of Delaware); and

(3) *Thomas W. Scott, Jr., individually and on behalf of all others similarly situated v. Encore Acquisition Company et al.* (filed November 6, 2009 in the District Court of Tarrant County, Texas).

The *Teamsters* and *Scott* lawsuits also name Denbury as a defendant. The complaints generally allege that (1) our directors breached their fiduciary duties in negotiating and approving the Merger and by administering a sale process that failed to maximize shareholder value and (2) we, and, in the case of the *Teamsters* and *Scott* complaints, Denbury aided and abetted our directors in breaching their fiduciary duties. The *Teamsters* complaint also alleges that our directors and executives stand to receive substantial financial benefits if the Merger is consummated on its current terms. The plaintiffs in these lawsuits seek, among other things, to enjoin the Merger and to rescind the Merger Agreement. We and Denbury have entered into a Memorandum of Understanding with the plaintiffs in these lawsuits agreeing in principle to the settlement of the lawsuits based upon inclusion in the joint proxy statement/prospectus of additional disclosures requested by the plaintiffs, and agreeing that the parties to the lawsuits will use best efforts to enter into a definitive settlement agreement and seek court approval for the settlement which would be binding on all of our shareholders who do not opt-out of the settlement.

ITEM 4. *SUBMISSION OF MATTERS TO A VOTE OF SECURITY HOLDERS*

There were no matters submitted to a vote of stockholders during the fourth quarter of 2009.

ENCORE ACQUISITION COMPANY

PART II

ITEM 5. *MARKET FOR REGISTRANT S COMMON EQUITY, RELATED STOCKHOLDER MATTERS AND ISSUER PURCHASES OF EQUITY SECURITIES*

Our common stock, par value $0.01 per share, is listed on the NYSE under the symbol EAC. The following table sets forth high and low sales prices of our common stock for the periods indicated:

	High	Low
2009		
Quarter ended December 31	$ 49.00	$ 35.64
Quarter ended September 30	$ 39.93	$ 25.53
Quarter ended June 30	$ 39.01	$ 22.30
Quarter ended March 31	$ 32.11	$ 17.04
2008		
Quarter ended December 31	$ 41.05	$ 17.89
Quarter ended September 30	$ 79.62	$ 36.84
Quarter ended June 30	$ 77.35	$ 38.45
Quarter ended March 31	$ 40.74	$ 26.10

On February 17, 2010, the closing sales price of our common stock as reported by the NYSE was $50.03 per share and we had approximately 418 shareholders of record. This number does not include owners for whom common stock may be held in street name.

Purchases of Equity Securities by the Issuer and Affiliated Purchasers

In October 2008, we announced that the Board authorized a share repurchase program of up to $40 million of our common stock. As of December 31, 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 fourth quarter of 2009, we did not repurchase any shares of our outstanding common stock under the share repurchase program. As of December 31, 2009, approximately $22.8 million of our common stock remained authorized for repurchase.

Dividends

No dividends have been declared or paid on our common stock. We anticipate that we will retain all future earnings and other cash resources for the future operation and development of our business. Accordingly, we do not intend to declare or pay any cash dividends in the foreseeable future. Payment of any future dividends will be at the discretion of the Board after taking into account many factors, including our operating results, financial condition, current and anticipated cash needs, and plans for expansion. The declaration and payment of dividends is restricted by our existing revolving credit facility and the indentures governing our senior subordinated notes. Future debt agreements may also restrict our ability to pay dividends.

Table of Contents

ENCORE ACQUISITION COMPANY

Stock Performance Graph

The following graph compares our cumulative total stockholder return during the period from January 1, 2005 to December 31, 2009 with total stockholder return during the same period for the Independent Oil and Gas Index and the Standard & Poor s 500 Index. The graph assumes that $100 was invested in our common stock and each index on January 1, 2005 and that all dividends, if any, were reinvested. The following graph is being furnished pursuant to SEC rules and will not be incorporated by reference into any filing under the Securities Act of 1933 or the Exchange Act except to the extent we specifically incorporate it by reference.

Comparison of Total Return Since January 1, 2005 Among Encore Acquisition Company, the Standard & Poor s 500 Index, and the Independent Oil and Gas Index

36

Table of Contents

ENCORE ACQUISITION COMPANY

ITEM 6. ***SELECTED FINANCIAL DATA***

The following table shows selected historical financial data for the periods and as of the periods indicated. The following selected consolidated financial and operating data should be read in conjunction with Item 7. Management s Discussion and Analysis of Financial Condition and Results of Operations and Item 8. Financial Statements and Supplementary Data :

	Year Ended December 31,(a)				
	2009	2008	2007	2006	2005
	(In thousands, except per share amounts)				
Consolidated Statements of Operations Data:					
Revenues(b):					
Oil	$ 549,391	$ 897,443	$ 562,817	$ 346,974	$ 307,959
Natural gas	131,185	227,479	150,107	146,325	149,365
Marketing(c)	4,840	10,496	42,021	147,563	
Total revenues	685,416	1,135,418	754,945	640,862	457,324
Expenses:					
Production:					
Lease operating(d)	165,062	175,115	143,426	98,194	69,744
Production, ad valorem, and severance taxes	69,539	110,644	74,585	49,780	45,601
Depletion, depreciation, and amortization	290,776	228,252	183,980	113,463	85,627
Impairment of long-lived assets(e)	9,979	59,526			
Exploration	52,488	39,207	27,726	30,519	14,443
General and administrative(d)	54,024	48,421	39,124	23,194	17,268
Marketing(c)	3,994	9,570	40,549	148,571	
Derivative fair value loss (gain)(f)	59,597	(346,236)	112,483	(24,388)	5,290
Loss on early redemption of debt(g)					19,477
Provision for doubtful accounts	7,686	1,984	5,816	1,970	231
Other operating	25,761	12,975	17,066	8,053	9,254
Total expenses	738,906	339,458	644,755	449,356	266,935
Operating income (loss)	(53,490)	795,960	110,190	191,506	190,389
Other income (expenses):					
Interest	(79,017)	(73,173)	(88,704)	(45,131)	(34,055)
Other	2,447	3,898	2,667	1,429	1,039
Total other expenses	(76,570)	(69,275)	(86,037)	(43,702)	(33,016)

Income (loss) before income taxes	(130,060)	726,685	24,153	147,804	157,373
Income tax benefit (provision)	32,173	(241,621)	(14,476)	(55,406)	(53,948)
Consolidated net income (loss)	(97,887)	485,064	9,677	92,398	103,425
Less: net loss (income) attributable to noncontrolling interest	16,752	(54,252)	7,478		
Net income (loss) attributable to EAC stockholders	$ (81,135)	$ 430,812	$ 17,155	$ 92,398	$ 103,425
Net income (loss) per common share:					
Basic	$ (1.54)	$ 8.10	$ 0.32	$ 1.75	$ 2.10
Diluted	$ (1.54)	$ 8.01	$ 0.31	$ 1.74	$ 2.07
Weighted average common shares outstanding:					
Basic	52,634	52,270	53,170	51,865	48,682
Diluted	52,634	52,866	53,629	52,356	49,303

ENCORE ACQUISITION COMPANY

	Year Ended December 31,(a)				
	2009	2008	2007	2006	2005
	(In thousands, except per unit amounts)				
Total Production Volumes:					
Oil (Bbls)	10,016	10,050	9,545	7,335	6,871
Natural gas (Mcf)	33,919	26,374	23,963	23,456	21,059
Combined (BOE)	15,669	14,446	13,539	11,244	10,381
Average Realized Prices:					
Oil ($/Bbl)	$ 54.85	$ 89.30	$ 58.96	$ 47.30	$ 44.82
Natural gas ($/Mcf)	3.87	8.63	6.26	6.24	7.09
Combined ($/BOE)	43.43	77.87	52.66	43.87	44.05
Average Costs per BOE:					
Lease operating(d)	$ 10.53	$ 12.12	$ 10.59	$ 8.73	$ 6.72
Production, ad valorem, and severance taxes	4.44	7.66	5.51	4.43	4.39
Depletion, depreciation, and amortization	18.56	15.80	13.59	10.09	8.25
Impairment of long-lived assets(e)	0.64	4.12			
Exploration	3.35	2.71	2.05	2.71	1.39
General and administrative(d)	3.45	3.35	2.89	2.06	1.67
Derivative fair value loss (gain)(f)	3.80	(23.97)	8.31	(2.17)	0.51
Provision for doubtful accounts	0.49	0.14	0.43	0.18	0.02
Other operating	1.64	0.90	1.26	0.71	0.89
Marketing, net of revenues(c)	(0.05)	(0.06)	(0.11)	0.09	
Consolidated Statements of Cash Flows Data:					
Cash provided by (used in):					
Operating activities	$ 745,677	$ 663,237	$ 319,707	$ 297,333	$ 292,269
Investing activities	(769,430)	(728,346)	(929,556)	(397,430)	(573,560)
Financing activities	35,672	65,444	610,790	99,206	281,842

	As of December 31,(a)				
	2009	2008	2007	2006	2005
	(In thousands)				
Proved Reserves:					
Oil (Bbls)	147,094	134,452	188,587	153,434	148,387
Natural gas (Mcf)	439,072	307,520	256,447	306,764	283,865
Combined (BOE)	220,273	185,705	231,328	204,561	195,698
Consolidated Balance Sheets Data:					
Working capital	$ (62,854)	$ 188,678	$ (16,220)	$ (40,745)	$ (56,838)
Total assets	3,663,961	3,633,195	2,784,561	2,006,900	1,705,705
Long-term debt	1,214,097	1,319,811	1,120,236	661,696	673,189

Equity	1,630,833	1,483,248	1,070,689	816,865	546,781

(a) We acquired certain oil and natural gas properties and related assets in the Mid-Continent and east Texas regions in August 2009. We acquired certain oil and natural gas properties and related assets in the Big Horn and Williston Basins in March 2007 and April 2007, respectively. We also acquired Crusader Energy Corporation in October 2005. The operating results of these acquisitions are included in our Consolidated Statements of Operations from the date of acquisition forward. We disposed of certain oil and natural gas properties and related assets in the Mid-Continent in June 2007. The operating results of this disposition are included in our Consolidated Statements of Operations through the date of disposition.

(b) For 2009, 2008, 2007, 2006, and 2005, we reduced oil and natural gas revenues for net profits interests owned by others by $31.8 million, $56.5 million, $32.5 million, $23.4 million, and $21.2 million, respectively.

ENCORE ACQUISITION COMPANY

(c) In 2006, we began purchasing third-party oil Bbls from a counterparty other than to whom the Bbls were sold for aggregation and sale with our own equity production in various markets. These purchases assisted us in marketing our production by decreasing our dependence on individual markets. These activities allowed us to aggregate larger volumes, facilitated our efforts to maximize the prices we received for production, provided for a greater allocation of future pipeline capacity in the event of curtailments, and enabled us to reach other markets. In 2007, we discontinued the purchase of oil from third party companies as market conditions changed and pipeline space was gained. Implementing this change allowed us to focus on the marketing of our own oil production, leveraging newly gained pipeline space, and delivering oil to various newly developed markets in an effort to maximize the value of the oil at the wellhead. In March 2007, ENP acquired a natural gas pipeline as part of the Big Horn Basin asset acquisition. Natural gas volumes are purchased from numerous gas producers at the inlet to the pipeline and resold downstream to various local and off-system markets.

(d) On January 1, 2006, we adopted the provisions of ASC 718, 505-50, and 260-10-60-1A (formerly SFAS No. 123R, *Share-Based Payment*). Due to the adoption of ASC 718, 505-50, and 260-10-60-1A, non-cash equity-based compensation expense for 2005 has been reclassified to allocate the amount to the same respective income statement lines as the respective employees cash compensation. In 2005, this resulted in increases in LOE of $1.3 million ($0.13 per BOE) and in general and administrative (G&A) expense of $2.6 million ($0.25 per BOE).

(e) During 2009 and 2008, circumstances indicated that the carrying value of certain of our oil and natural gas properties in the Tuscaloosa Marine Shale may not be recoverable. For the proved oil and natural gas property costs, we compared the assets carrying amounts to the undiscounted expected future net cash flows, which indicated a need for an impairment charge. We then compared the net carrying amounts of the impaired assets to their estimated fair value, which resulted in a pretax write-down of the value of oil and natural gas properties. For the unproved acreage costs, we recorded a valuation allowance to reflect the portion of the property costs that we believe will not be transferred to proved properties over the remaining life of the lease. The impairment of proved oil and natural gas properties and unproved acreage in the Tuscaloosa Marine Shale totaled $10.0 million and $59.5 million during 2009 and 2008, respectively. Fair value was determined using estimates of future production volumes and estimates of future prices we might receive for these volumes, discounted to a present value.

(f) During July 2006, we elected to discontinue hedge accounting prospectively for all of our remaining commodity derivative contracts which were previously accounted for as hedges. From that point forward, all mark-to-market gains or losses on all commodity derivative contracts are recorded in Derivative fair value loss (gain) while in periods prior to that point, only the ineffective portions of commodity derivative contracts which were designated as hedges were recorded in Derivative fair value loss (gain).

(g) In 2005, we recorded a $19.5 million loss on early redemption of debt related to the redemption premium and the expensing of unamortized debt issuance costs of our 83/8% Senior Subordinated Notes due 2012. We redeemed all $150 million of such notes with proceeds received from the issuance of $300 million of our 6.0% Senior Subordinated Notes due 2015.

ENCORE ACQUISITION COMPANY

ITEM 7. ***MANAGEMENT S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS***

The following discussion and analysis of our consolidated financial condition and results of operations should be read in conjunction with our consolidated financial statements and notes and supplementary data thereto included in Item 8. Financial Statements and Supplementary Data. The following discussion and analysis contains forward-looking statements including, without limitation, statements relating to our plans, strategies, objectives, expectations, intentions, and resources. Actual results could differ materially from those discussed in the forward-looking statements. We do not undertake to update, revise, or correct any of the forward-looking information unless required to do so under federal securities laws. Readers are cautioned that such forward-looking statements should be read in conjunction with our disclosures under the headings: Information Concerning Forward-Looking Statements and Item 1A. Risk Factors.

Introduction

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

Overview of Business

2009 Highlights

Results of Operations

Comparison of 2009 to 2008

Comparison of 2008 to 2007

Capital Commitments, Capital Resources, and Liquidity

Changes in Prices

Critical Accounting Policies and Estimates

New Accounting Pronouncements

Information Concerning Forward-Looking Statements

Overview of Business

We are a Delaware corporation engaged in the acquisition, development, exploitation, exploration, and production of oil and natural gas reserves from onshore fields in the United States. Our business strategies include:

Maintaining an active development program to maximize existing reserves and production;

Utilizing EOR techniques to maximize existing reserves and production;

Expanding our reserves, production, and development inventory through a disciplined acquisition program;

Exploring for reserves; and

Operating in a cost effective, efficient, and safe manner.

As previously discussed, on October 31, 2009, we entered into the Merger Agreement with Denbury pursuant to which we have agreed to merge with and into Denbury, with Denbury as the surviving entity. The Merger Agreement, which was unanimously approved by our Board and by Denbury s Board of Directors, provides for Denbury s acquisition of all of our issued and outstanding shares of common stock in a transaction valued at approximately $4.5 billion, including the assumption of debt and the value of our interest

Table of Contents

ENCORE ACQUISITION COMPANY

in ENP. We expect to complete the Merger during the first quarter of 2010, although completion by any particular date cannot be assured.

At December 31, 2009, our oil and natural gas properties had estimated total proved reserves of 147.1 MMBbls of oil and 439.1 Bcf of natural gas, based on 2009 12-month average market prices of $61.18 per Bbl of oil and $3.83 per Mcf of natural gas. On a BOE basis, our proved reserves were 220.3 MMBOE at December 31, 2009, of which approximately 67 percent was oil, approximately 80 percent was proved developed, and approximately 20 proved undeveloped.

Our financial results and ability to generate cash depend upon many factors, particularly the price of oil and natural gas. Average NYMEX prices deteriorated significantly in 2009. Our oil wellhead differentials to NYMEX deteriorated slightly in 2009 as we realized 89 percent of the average NYMEX oil price, as compared to 90 percent in 2008. Our natural gas wellhead differentials to NYMEX improved in 2009 as we realized 97 percent of the average NYMEX natural gas price, as compared to 95 percent in 2008. Commodity prices are influenced by many factors that are outside of our control. We cannot accurately predict future commodity prices. For this reason, we attempt to mitigate the effect of commodity price risk by entering into commodity derivative contracts for a portion of our forecasted production. For a discussion of factors that influence commodity prices and risks associated with our commodity derivative contracts, please read Item 1A. Risk Factors.

2009 Highlights

Our financial and operating results for 2009 included the following:

- Our average daily production volumes increased nine percent to 42,929 BOE/D as compared to 39,470 BOE/D in 2008. Oil represented 64 percent and 70 percent of our total production volumes in 2009 and 2008, respectively.

- We invested $706.5 million in oil and natural gas activities, of which $286.9 million was invested in development, exploitation, and exploration activities, yielding 112 gross (42.3 net) productive wells, and $419.5 million was invested in acquisitions, primarily related to our EXCO asset acquisition.

- In September, we issued 2,750,000 shares of our common stock at a price to the public of $37.40 per common share. The net proceeds of approximately $100.6 million were used to reduce outstanding borrowings under our revolving credit facility.

- In August, we acquired certain oil and natural gas properties and related assets in the Mid-Continent and East Texas from EXCO for approximately $357.4 million in cash (including a deposit of $37.5 million made in June 2009).

- In August, we sold the Rockies and Permian Basin Assets to ENP for approximately $179.6 million in cash.

- In June, we sold the Williston Basin Assets to ENP for approximately $25.2 million in cash.

- In April, we issued $225 million of our 9.5% Senior Subordinated Notes due 2016. We used the net proceeds of approximately $202.4 million to reduce outstanding borrowings under our revolving credit facility.

In March, we elected to monetize certain of our 2009 oil derivative contracts and received net proceeds of approximately $190.4 million, which were used to reduce outstanding borrowings under our revolving credit facility.

In January, we sold the Arkoma Basin Assets to ENP for approximately $46.4 million in cash.

Table of Contents

ENCORE ACQUISITION COMPANY

Results of Operations

Comparison of 2009 to 2008

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

	Year Ended December 31, 2009	2008	*Increase/(Decrease) $*	*%*
Revenues (in thousands):				
Oil wellhead	$ 549,391	$ 900,300	*$ (350,909)*	
Oil commodity derivative contracts		(2,857)	*2,857*	
Total oil revenues	$ 549,391	$ 897,443	*$ (348,052)*	*(39)%*
Natural gas wellhead	$ 131,185	$ 227,479	*$ (96,294)*	*(42)%*
Combined wellhead	$ 680,576	$ 1,127,779	*$ (447,203)*	*(40)%*
Combined commodity derivative contracts		(2,857)	*2,857*	
Total combined oil and natural gas revenues	$ 680,576	$ 1,124,922	*$ (444,346)*	*(40)%*
Marketing	4,840	10,496	*(5,656)*	*(54)%*
Total revenues	$ 685,416	$ 1,135,418	*$ (450,002)*	*(40)%*
Average realized prices:				
Oil wellhead ($/Bbl)	$ 54.85	$ 89.58	*$ (34.73)*	
Oil commodity derivative contracts ($/Bbl)		(0.28)	*0.28*	
Total oil revenues ($/Bbl)	$ 54.85	$ 89.30	*$ (34.45)*	*(39)%*
Natural gas wellhead ($/Mcf)	$ 3.87	$ 8.63	*$ (4.76)*	*(55)%*
Combined wellhead ($/BOE)	$ 43.43	$ 78.07	*$ (34.64)*	
Combined commodity derivative contracts ($/BOE)		(0.20)	*0.20*	
Total combined oil and natural gas revenues ($/BOE)	$ 43.43	$ 77.87	*$ (34.44)*	*(44)%*
Total production volumes:				
Oil (MBbls)	10,016	10,050	*(34)*	*0%*
Natural gas (MMcf)	33,919	26,374	*7,545*	*29%*
Combined (MBOE)	15,669	14,446	*1,223*	*8%*
Average daily production volumes:				

Oil (Bbl/D)	27,441	27,459	*(18)*	*0%*
Natural gas (Mcf/D)	92,928	72,060	*20,868*	*29%*
Combined (BOE/D)	42,929	39,470	*3,459*	*9%*
Average NYMEX prices:				
Oil (per Bbl)	$ 61.95	$ 99.75	*$ (37.80)*	*(38)%*
Natural gas (per Mcf)	$ 3.99	$ 9.04	*$ (5.05)*	*(56)%*

Oil revenues decreased 39 percent from $897.4 million in 2008 to $549.4 million in 2009 as a result of a $34.73 per Bbl decrease in our average realized oil price and a 34 MBbl decrease in our oil production volumes. Our lower average realized oil price decreased oil revenues by approximately $347.8 million and was primarily due to a lower average NYMEX price, which decreased from $99.75 per Bbl in 2008 to $61.95

ENCORE ACQUISITION COMPANY

per Bbl in 2009. Our lower oil production volumes decreased oil revenues by approximately $3.1 million. Oil revenues in 2008 were also reduced by approximately $2.9 million, or $0.28 per Bbl, for oil derivative contracts previously designated as hedges. In 2009 and 2008, our average daily production volumes were decreased by 1,721 BOE/D and 1,530 BOE/D, respectively, for net profits interests related to our CCA properties, which reduced our oil wellhead revenues by $31.3 million and $55.3 million, respectively.

Natural gas revenues decreased 42 percent from $227.5 million in 2008 to $131.2 million in 2009 as a result of a $4.76 per Mcf decrease in our average realized natural gas price, partially offset by a 7,545 MMcf increase in natural gas production volumes. Our lower average realized natural gas price decreased natural gas revenues by approximately $161.4 million and was primarily due to a lower average NYMEX price, which decreased from $9.04 per Mcf in 2008 to $3.99 per Mcf in 2009. Our higher natural gas production volumes increased natural gas revenues by approximately $65.1 million was primarily the result of successful development programs in our Permian Basin and Mid-Continent regions and our acquisitions of properties from EXCO in August 2009.

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

	Year Ended December 31, 2009	Year Ended December 31, 2008
Average oil wellhead ($/Bbl)	$ 54.85	$ 89.58
Average NYMEX ($/Bbl)	$ 61.95	$ 99.75
Differential to NYMEX	$ (7.10)	$ (10.17)
Average oil wellhead to NYMEX percentage	89%	90%
Average natural gas wellhead ($/Mcf)	$ 3.87	$ 8.63
Average NYMEX ($/Mcf)	$ 3.99	$ 9.04
Differential to NYMEX	$ (0.12)	$ (0.41)
Average natural gas wellhead to NYMEX percentage	97%	95%

Our average oil wellhead price as a percentage of the average NYMEX price was 89 percent in 2009 as compared to 90 percent in 2008.

Our average natural gas wellhead price as a percentage of the average NYMEX price was 97 percent in 2009 as compared to 95 percent in 2008.

Marketing revenues decreased 54 percent from $10.5 million in 2008 to $4.8 million in 2009 primarily as a result of a reduction in natural gas throughput in our Wildhorse pipeline and the decrease in natural gas prices. 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.

Table of Contents

ENCORE ACQUISITION COMPANY

Expenses. The following table provides the components of our expenses for the periods indicated:

	Year Ended December 31, 2009	Year Ended December 31, 2008	*Increase/(Decrease) $*	*Increase/(Decrease) %*
Expenses (in thousands):				
Production:				
Lease operating	$ 165,062	$ 175,115	*$ (10,053)*	
Production, ad valorem, and severance taxes	69,539	110,644	*(41,105)*	
Total production expenses	234,601	285,759	*(51,158)*	*(18)%*
Other:				
Depletion, depreciation, and amortization	290,776	228,252	*62,524*	
Impairment of long-lived assets	9,979	59,526	*(49,547)*	
Exploration	52,488	39,207	*13,281*	
General and administrative	54,024	48,421	*5,603*	
Marketing	3,994	9,570	*(5,576)*	
Derivative fair value loss (gain)	59,597	(346,236)	*405,833*	
Provision for doubtful accounts	7,686	1,984	*5,702*	
Other operating	25,761	12,975	*12,786*	
Total operating	738,906	339,458	*399,448*	*118%*
Interest	79,017	73,173	*5,844*	
Income tax provision (benefit)	(32,173)	241,621	*(273,794)*	
Total expenses	$ 785,750	$ 654,252	*$ 131,498*	*20%*
Expenses (per BOE):				
Production:				
Lease operating	$ 10.53	$ 12.12	*$ (1.59)*	
Production, ad valorem, and severance taxes	4.44	7.66	*(3.22)*	
Total production expenses	14.97	19.78	*(4.81)*	*(24)%*
Other:				
Depletion, depreciation, and amortization	18.56	15.80	*2.76*	
Impairment of long-lived assets	0.64	4.12	*(3.48)*	
Exploration	3.35	2.71	*0.64*	
General and administrative	3.45	3.35	*0.10*	
Marketing	0.25	0.66	*(0.41)*	
Derivative fair value loss (gain)	3.80	(23.97)	*27.77*	
Provision for doubtful accounts	0.49	0.14	*0.35*	
Other operating	1.64	0.90	*0.74*	
Total operating	47.15	23.49	*23.66*	*101%*

Interest		5.04		5.07		*(0.03)*	
Income tax provision (benefit)		(2.05)		16.73		*(18.78)*	
Total expenses	$	50.14	$	45.29	*$*	*4.85*	*11%*

Production expenses. Total production expenses decreased 18 percent from $285.8 million in 2008 to $234.6 million in 2009. Our production margin decreased 47 percent from $842.0 million in 2008 to $446.0 million in 2009. Total oil and natural gas wellhead revenues per BOE decreased by 44 percent and

ENCORE ACQUISITION COMPANY

total production expenses per BOE decreased by 24 percent. On a per BOE basis, our production margin decreased 51 percent to $28.46 per BOE in 2009 as compared to $58.29 per BOE in 2008.

Production expense attributable to LOE decreased $10.1 million from $175.1 million in 2008 to $165.1 million in 2009 as a result of a $1.59 decrease in the average per BOE rate, partially offset by higher production volumes. Our lower average LOE per BOE rate decreased LOE by approximately $24.9 million and was primarily due to decreases in natural gas prices resulting in lower electricity costs and gas plant fuel costs and lower prices paid to oilfield service companies and suppliers. Our higher production volumes increased LOE by approximately $14.8 million.

Production expense attributable to production taxes decreased $41.1 million from $110.6 million in 2008 to $69.5 million in 2009 primarily due to lower wellhead revenues, which exclude the effects of commodity derivative contracts. As a percentage of wellhead revenues, production taxes increased to 10.2 percent in 2009 as compared to 9.8 percent in 2008 primarily due to higher ad valorem taxes, which are based on production volumes as opposed to a percentage of wellhead revenues.

Depletion, depreciation, and amortization (DD&A) expense. DD&A expense increased $62.5 million from $228.3 million in 2008 to $290.8 million in 2009 as a result of a $2.76 increase in the per BOE rate and higher production volumes. Our higher average DD&A per BOE rate increased DD&A expense by approximately $43.2 million and was primarily due to the decrease in our proved reserves at the beginning of 2009 as a result of lower average commodity prices, partially offset by reserves added during 2009 through our EXCO asset acquisition. Our higher production volumes increased DD&A expense by approximately $19.3 million.

Impairment of long-lived assets. During 2009 and 2008, circumstances indicated that the carrying value of certain of our oil and natural gas properties in the Tuscaloosa Marine Shale may not be recoverable. For the proved oil and natural gas property costs, we compared the assets carrying value to the undiscounted expected future net cash flows, which indicated a need for an impairment charge. We then compared the net book value of the impaired assets to their estimated discounted value, which resulted in a pretax write-down of the value of oil and natural gas properties. For the unproved acreage costs, we recorded a valuation allowance to reflect the portion of the property costs that we believe will not be transferred to proved properties over the remaining life of the lease. The impairment of proved oil and natural gas properties and unproved acreage in the Tuscaloosa Marine Shale totaled of $10.0 million and $59.5 million during 2009 and 2008, respectively. Fair value was determined using estimates of future production volumes and estimates of future prices we might receive for these volumes, discounted to a present value.

As of December 31, 2009, we do not have any unproved oil and natural gas properties in the Tuscaloosa Marine Shale whose carrying value has not been written down to zero.

ENCORE ACQUISITION COMPANY

Exploration expense. Exploration expense increased $13.3 million from $39.2 million in 2008 to $52.5 million in 2009. During 2009, we expensed 5.6 net exploratory dry holes totaling $25.4 million. During 2008, we expensed 3.8 net exploratory dry holes totaling $14.7 million. Impairment of unproved acreage increased $5.1 million from $20.2 million in 2008 to $25.3 million in 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 provides the components of exploration expenses for the periods indicated:

	Year Ended December 31, 2009	Year Ended December 31, 2008	*Increase (Decrease)*
	(In thousands)		
Dry holes	$ 25,407	$ 14,683	*$ 10,724*
Geological and seismic	1,022	2,851	*(1,829)*
Delay rentals	773	1,482	*(709)*
Impairment of unproved acreage	25,286	20,191	*5,095*
Total	$ 52,488	$ 39,207	*$ 13,281*

G&A expense. G&A expense increased $5.6 million from $48.4 million in 2008 to $54.0 million in 2009 primarily due to retention bonuses paid in August 2009 related to our 2008 strategic alternatives process and the expensing of transaction costs related to our EXCO asset acquisition.

Marketing expense. Marketing expense decreased $5.6 million from $9.6 million in 2008 to $4.0 million in 2009 as a result of a reduction in natural gas throughput in our Wildhorse pipeline and the decrease in natural gas prices. 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 (gain). During 2009, we recorded a $59.6 million derivative fair value loss as compared to a $346.2 million derivative fair value gain in 2008, the components of which were as follows:

	Year Ended December 31, 2009	Year Ended December 31, 2008	*Increase/ (Decrease)*
	(In thousands)		
Ineffectiveness	$ 2	$ 372	*$ (370)*
Mark-to-market loss (gain)	350,365	(365,495)	*715,860*
Premium amortization	98,395	62,352	*36,043*
Settlements	(389,165)	(43,465)	*(345,700)*
Total derivative fair value loss (gain)	$ 59,597	$ (346,236)	*$ 405,833*

Provision for doubtful accounts. In 2009 and 2008, we recorded a provision for doubtful accounts of $7.7 million and $2.0 million, respectively, primarily for the payout allowance related to the ExxonMobil joint development agreement.

Other operating expense. Other operating expense increased $12.8 million from $13.0 million in 2008 to $25.8 million in 2009, primarily due to a $6.5 million adjustment to the carrying value of pipe and other tubular inventory whose market value had declined below cost and higher gathering and transportation fees.

Interest expense. Interest expense increased $5.8 million from $73.2 million in 2008 to $79.0 million in 2009 primarily due to the issuance of our 9.5% Notes in April 2009. The weighted average interest rate for all long-term debt for 2009 was 5.8 percent as compared to 5.6 percent for 2008.

Table of Contents

ENCORE ACQUISITION COMPANY

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

	Year Ended December 31, 2009	2008	*Increase/ (Decrease)*
	(In thousands)		
6.25% Senior Subordinated Notes	$ 9,751	$ 9,727	*$ 24*
6.0% Senior Subordinated Notes	18,585	18,550	*35*
9.5% Senior Subordinated Notes	15,999		*15,999*
7.25% Senior Subordinated Notes	11,005	10,996	*9*
Revolving credit facilities	18,253	31,038	*(12,785)*
Other	5,424	2,862	*2,562*
Total	$ 79,017	$ 73,173	*$ 5,844*

Income taxes. In 2009, we recorded an income tax benefit of $32.2 million as compared to an income tax provision of $241.6 million in 2008. In 2009, we had a loss before income taxes of $130.1 million as compared to income before income taxes of $726.7 million in 2008. Our effective tax rate decreased to 24.7 percent in 2009 as compared to 33.2 percent in 2008 primarily due to the 2008 provision to return difference for the production activities deduction estimated at the end of 2008 due to a change in tax planning as a result of the monetization of hedges in the first quarter of 2009 and an increase in the effective state income tax rate due to changes in apportionment associated with our 2009 acquisitions.

Table of Contents

ENCORE ACQUISITION COMPANY

Comparison of 2008 to 2007

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

	Year Ended December 31, 2008	Year Ended December 31, 2007	*Increase/ (Decrease) $*	*%*
Revenues (in thousands):				
Oil wellhead	$ 900,300	$ 606,112	*$ 294,188*	
Oil commodity derivative contracts	(2,857)	(43,295)	*40,438*	
Total oil revenues	$ 897,443	$ 562,817	*$ 334,626*	*59%*
Natural gas wellhead	$ 227,479	$ 160,399	*$ 67,080*	
Natural gas commodity derivative contracts		(10,292)	*10,292*	
Total natural gas revenues	$ 227,479	$ 150,107	*$ 77,372*	*52%*
Combined wellhead	$ 1,127,779	$ 766,511	*$ 361,268*	
Combined commodity derivative contracts	(2,857)	(53,587)	*50,730*	
Total combined oil and natural gas revenues	1,124,922	712,924	*411,998*	*58%*
Marketing	10,496	42,021	*(31,525)*	*(75)%*
Total revenues	$ 1,135,418	$ 754,945	*$ 380,473*	*50%*
Average realized prices:				
Oil wellhead ($/Bbl)	$ 89.58	$ 63.50	*$ 26.08*	
Oil commodity derivative contracts ($/Bbl)	(0.28)	(4.54)	*4.26*	
Total oil revenues ($/Bbl)	$ 89.30	$ 58.96	*$ 30.34*	*51%*
Natural gas wellhead ($/Mcf)	$ 8.63	$ 6.69	*$ 1.94*	
Natural gas commodity derivative contracts ($/Mcf)		(0.43)	*0.43*	
Total natural gas revenues ($/Mcf)	$ 8.63	$ 6.26	*$ 2.37*	*38%*
Combined wellhead ($/BOE)	$ 78.07	$ 56.62	*$ 21.45*	
Combined commodity derivative contracts ($/BOE)	(0.20)	(3.96)	*3.76*	
Total combined oil and natural gas revenues ($/BOE)	$ 77.87	$ 52.66	*$ 25.21*	*48%*
Total production volumes:				

Oil (MBbls)	10,050	9,545	*505*	*5%*
Natural gas (MMcf)	26,374	23,963	*2,411*	*10%*
Combined (MBOE)	14,446	13,539	*907*	*7%*
Average daily production volumes:				
Oil (Bbl/D)	27,459	26,152	*1,307*	*5%*
Natural gas (Mcf/D)	72,060	65,651	*6,409*	*10%*
Combined (BOE/D)	39,470	37,094	*2,376*	*6%*
Average NYMEX prices:				
Oil (per Bbl)	$ 99.75	$ 72.45	*$ 27.30*	*38%*
Natural gas (per Mcf)	$ 9.04	$ 6.86	*$ 2.18*	*32%*

48

ENCORE ACQUISITION COMPANY

Oil revenues increased 59 percent from $562.8 million in 2007 to $897.4 million in 2008 as a result of an increase in our average realized oil price and an increase in oil production volumes of 505 MBbls. The increase in oil production volumes contributed approximately $32.1 million in additional oil revenues and was primarily the result of a full year of production from our Big Horn Basin acquisition in March 2007 and our Williston Basin acquisition in April 2007, as well as our development program in the Bakken.

Our average realized oil price increased $30.34 per Bbl from 2007 to 2008 primarily as a result of an increase in our average realized oil wellhead price, which increased oil revenues by approximately $262.1 million, or $26.08 per Bbl. Our average realized oil wellhead price increased primarily as a result of the increase in the average NYMEX price from $72.45 per Bbl in 2007 to $99.75 per Bbl in 2008.

During July 2006, we elected to discontinue hedge accounting prospectively for all remaining commodity derivative contracts which were previously accounted for as hedges. While this change had no effect on our cash flows, results of operations are affected by mark-to-market gains and losses, which fluctuate with the changes in oil and natural gas prices. As a result, oil revenues for 2008 included amortization of net losses on certain commodity derivative contracts that were previously designated as hedges of approximately $2.9 million, or $0.28 per Bbl, while 2007 included approximately $43.3 million, or $4.54 per Bbl, of net losses.

Our average daily production volumes were decreased by 1,530 BOE/D and 1,466 BOE/D in 2008 and 2007, respectively, for net profits interests related to our CCA properties, which reduced our oil wellhead revenues by $55.3 million and $31.9 million in 2008 and 2007, respectively.

Natural gas revenues increased 52 percent from $150.1 million in 2007 to $227.5 million in 2008 as a result of an increase in our average realized natural gas price and an increase in natural gas production volumes of 2,411 MMcf. The increase in natural gas production volumes contributed approximately $16.1 million in additional natural gas revenues and was primarily the result of our development program in our Permian Basin and Mid-Continent regions.

Our average realized natural gas price increased $2.37 per Mcf from 2007 to 2008 primarily as a result of an increase in our average realized natural gas wellhead price, which increased natural gas revenues by approximately $50.9 million, or $1.94 per Mcf. Our average realized natural gas wellhead price increased primarily as a result of the increase in the average NYMEX price from $6.86 per Mcf in 2007 to $9.04 per Mcf in 2008. In addition, as a result of our discontinuance of hedge accounting in July 2006, natural gas revenues for 2007 included amortization of net losses on certain commodity derivative contracts that were previously designated as hedges of approximately $10.3 million, or $0.43 per Mcf.

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

	Year Ended December 31, 2008	Year Ended December 31, 2007
Average oil wellhead ($/Bbl)	$ 89.58	$ 63.50
Average NYMEX ($/Bbl)	$ 99.75	$ 72.45
Differential to NYMEX	$ (10.17)	$ (8.95)

Average oil wellhead to NYMEX percentage	90%	88%
Average natural gas wellhead ($/Mcf)	$ 8.63	$ 6.69
Average NYMEX ($/Mcf)	$ 9.04	$ 6.86
Differential to NYMEX	$ (0.41)	$ (0.17)
Average natural gas wellhead to NYMEX percentage	95%	98%

Our average oil wellhead price as a percentage of the average NYMEX price was 90 percent in 2008 as compared to 88 percent in 2007. Our average natural gas wellhead price as a percentage of the average NYMEX price was 95 percent in 2008 as compared to 98 percent in 2007.

Table of Contents

ENCORE ACQUISITION COMPANY

Marketing revenues decreased 75 percent from $42.0 million in 2007 to $10.5 million in 2008 primarily as a result of discontinuing the purchase of oil from third party companies as market conditions changed and historical pipeline space was realized. Implementing this change allowed us to focus on the marketing of our own production, leveraging newly gained pipeline space, and delivering oil to various newly developed markets in an effort to maximize the value of the oil at the wellhead. In March 2007, ENP acquired a natural gas pipeline from Anadarko as part of the Big Horn Basin asset acquisition. Natural gas volumes are purchased from numerous gas producers at the inlet to the pipeline and resold downstream to various local and off-system markets.

Expenses. The following table provides the components of our expenses for the periods indicated:

	Year Ended December 31,		*Increase/ (Decrease)*	
	2008	**2007**	***$***	***%***
Expenses (in thousands):				
Production:				
Lease operating	$ 175,115	$ 143,426	*$ 31,689*	
Production, ad valorem, and severance taxes	110,644	74,585	*36,059*	
Total production expenses	285,759	218,011	*67,748*	*31%*
Other:				
Depletion, depreciation, and amortization	228,252	183,980	*44,272*	
Impairment of long-lived assets	59,526		*59,526*	
Exploration	39,207	27,726	*11,481*	
General and administrative	48,421	39,124	*9,297*	
Marketing	9,570	40,549	*(30,979)*	
Derivative fair value loss (gain)	(346,236)	112,483	*(458,719)*	
Provision for doubtful accounts	1,984	5,816	*(3,832)*	
Other operating	12,975	17,066	*(4,091)*	
Total operating	339,458	644,755	*(305,297)*	*(47)%*
Interest	73,173	88,704	*(15,531)*	
Income tax provision	241,621	14,476	*227,145*	
Total expenses	$ 654,252	$ 747,935	*$ (93,683)*	*(13)%*
Expenses (per BOE):				
Production:				
Lease operating	$ 12.12	$ 10.59	*$ 1.53*	
Production, ad valorem, and severance taxes	7.66	5.51	*2.15*	
Total production expenses	19.78	16.10	*3.68*	*23%*
Other:				
Depletion, depreciation, and amortization	15.80	13.59	*2.21*	
Impairment of long-lived assets	4.12		*4.12*	

Exploration		2.71		2.05		*0.66*	
General and administrative		3.35		2.89		*0.46*	
Marketing		0.66		2.99		*(2.33)*	
Derivative fair value loss (gain)		(23.97)		8.31		*(32.28)*	
Provision for doubtful accounts		0.14		0.43		*(0.29)*	
Other operating		0.90		1.26		*(0.36)*	
Total operating		23.49		47.62		*(24.13)*	*(51)%*
Interest		5.07		6.55		*(1.48)*	
Income tax provision		16.73		1.07		*15.66*	
Total expenses	$	45.29	$	55.24	*$*	*(9.95)*	*(18)%*

ENCORE ACQUISITION COMPANY

Production expenses. Total production expenses increased 31 percent from $218.0 million in 2007 to $285.8 million in 2008. Our production margin increased 54 percent to $842.0 million as compared to $548.5 million in 2007. Total oil and natural gas wellhead revenues per BOE increased by 38 percent while total production expenses per BOE increased by 23 percent. On a per BOE basis, our production margin increased 44 percent to $58.29 per BOE as compared to $40.52 per BOE for 2007.

Production expense attributable to LOE increased $31.7 million from $143.4 million in 2007 to $175.1 million in 2008 as a result of a $1.53 increase in the average per BOE rate, which contributed approximately $22.1 million of additional LOE, and an increase in production volumes, which contributed approximately $9.6 million of additional LOE. The increase in our average LOE per BOE rate was attributable to:

- increases in prices paid to oilfield service companies and suppliers;
- increases in natural gas prices resulting in higher electricity costs and gas plant fuel costs;
- higher compensation levels for engineers and other technical professionals; and
- an increase of approximately $4.7 million ($0.32 per BOE) for retention bonuses paid in August 2008 and approximately $4.1 million ($0.28 per BOE) for retention bonuses paid in August 2009, related to our strategic alternatives process.

Production expense attributable to production taxes increased $36.1 million from $74.6 million in 2007 to $110.6 million in 2008 primarily due to higher wellhead revenues, which exclude the effects of commodity derivative contracts. As a percentage of wellhead revenues, production taxes remained approximately constant at 9.8 percent in 2008 as compared to 9.7 percent in 2007.

DD&A expense. DD&A expense increased $44.3 million from $184.0 million in 2007 to $228.3 million in 2008 as a result of a $2.21 increase in the per BOE rate, which contributed approximately $32.0 million of additional DD&A expense, and an increase in production volumes, which contributed approximately $12.3 million of additional DD&A expense. The increase in our average DD&A per BOE rate was attributable to higher costs incurred resulting from increases in rig rates, pipe costs, and acquisition costs and the decrease in our total proved reserves to 185.7 MMBOE as of December 31, 2008 as compared to 231.3 MMBOE as of December 31, 2007.

Impairment of long-lived assets. During 2008, circumstances indicated that the carrying value of certain wells we drilled in the Tuscaloosa Marine Shale may not be recoverable. We compared the assets carrying value to the undiscounted expected future net cash flows, which indicated a need for an impairment charge. We then compared the net book value of the impaired assets to their estimated discounted value, which resulted in a pretax write-down of the value of proved oil and natural gas properties of $59.5 million. Fair value was determined using estimates of future production volumes and estimates of future prices we might receive for these volumes, discounted to a present value.

Exploration expense. Exploration expense increased $11.5 million from $27.7 million in 2007 to $39.2 million in 2008. During 2008, we expensed 3.8 net exploratory dry holes totaling $14.7 million. During 2007, we expensed 2.6 net exploratory dry holes totaling $14.7 million. Impairment of unproved acreage increased $9.4 million from $10.8 million in 2007 to $20.2 million in 2008, primarily due to our larger

ENCORE ACQUISITION COMPANY

unproved property base, as well as the impairment of certain acreage through the normal course of evaluation. The following table provides the components of exploration expenses for the periods indicated:

	Year Ended December 31, 2008	2007	*Increase*
	(In thousands)		
Dry holes	$ 14,683	$ 14,673	*$ 10*
Geological and seismic	2,851	1,455	*1,396*
Delay rentals	1,482	784	*698*
Impairment of unproved acreage	20,191	10,814	*9,377*
Total	$ 39,207	$ 27,726	*$ 11,481*

G&A expense. G&A expense increased $9.3 million from $39.1 million in 2007 to $48.4 million in 2008, primarily due to:

- a full year of ENP public entity expenses;
- higher activity levels;
- increased personnel costs due to intense competition for human resources within the industry; and
- an increase of approximately $2.9 million for retention bonuses paid in August 2008 and approximately $2.8 million for retention bonuses paid in August 2009, related to our strategic alternatives process;
- partially offset by a $3.1 million decrease in non-cash equity-based compensation.

Marketing expense. Marketing expense decreased $31.0 million from $40.5 million in 2007 to $9.6 million in 2008 primarily as a result of discontinuing purchasing oil from third party companies as market conditions changed and historical pipeline space was realized. Implementing this change allowed us to focus on the marketing of our own production, leveraging newly gained pipeline space, and delivering oil to various newly developed markets in an effort to maximize the value of the oil at the wellhead. In March 2007, ENP acquired a natural gas pipeline from Anadarko as part of the Big Horn Basin asset acquisition. Natural gas volumes are purchased from numerous gas producers at the inlet to the pipeline and resold downstream to various local and off-system markets.

Derivative fair value loss (gain). During 2008, we recorded a $346.2 million derivative fair value gain as compared to a $112.5 million derivative fair value loss in 2007, the components of which were as follows:

	Year Ended December 31, 2008	2007	*Increase/ (Decrease)*

	(In thousands)		
Ineffectiveness	$ 372	$	*$ 372*
Mark-to-market loss (gain)	(365,495)	36,272	*(401,767)*
Premium amortization	62,352	41,051	*21,301*
Settlements	(43,465)	35,160	*(78,625)*
Total derivative fair value loss (gain)	$ (346,236)	$ 112,483	*$ (458,719)*

The change in our derivative fair value loss (gain) was a result of the addition of commodity derivative contracts in the first part of 2008 when prices were high and the significant decrease in prices during the end of 2008, which favorably impacted the fair values of those contracts.

Provision for doubtful accounts. In 2008 and 2007, we recorded a provision for doubtful accounts of $2.0 million and $5.8 million, respectively, primarily for the payout allowance related to the ExxonMobil joint development agreement.

ENCORE ACQUISITION COMPANY

Other operating expense. Other operating expense decreased $4.1 million from $17.1 million in 2007 to $13.0 million in 2008, primarily due to a $7.4 million loss on the sale of certain Mid-Continent properties in 2007, partially offset by a $3.4 million increase during 2008 in third-party transportation costs to move our production to markets outside the immediate area of production.

Interest expense. Interest expense decreased $15.5 million from $88.7 million in 2007 to $73.2 million in 2008, primarily due to (1) the use of net proceeds from our Mid-Continent asset disposition and ENP s IPO to reduce weighted average outstanding borrowings on our revolving credit facilities, (2) a reduction in LIBOR, and (3) our use of interest rate swaps to fix the rate on a portion of outstanding borrowings on ENP s revolving credit facility. The weighted average interest rate for all long-term debt for 2008 was 5.6 percent as compared to 6.9 percent for 2007.

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

	Year Ended December 31, 2008	Year Ended December 31, 2007	*Increase/ (Decrease)*
	(In thousands)		
6.25% Senior Subordinated Notes	$ 9,727	$ 9,705	*$ 22*
6.0% Senior Subordinated Notes	18,550	18,517	*33*
7.25% Senior Subordinated Notes	10,996	10,988	*8*
Revolving credit facilities	31,038	46,085	*(15,047)*
Other	2,862	3,409	*(547)*
Total	$ 73,173	$ 88,704	*$ (15,531)*

Income taxes. In 2008, we recorded an income tax provision of $241.6 million as compared to $14.5 million in 2007. In 2008, we had income before income taxes of $726.7 million as compared to $24.2 million in 2007. Our effective tax rate decreased to 33.2 percent in 2008 as compared to 59.9 percent in 2007 primarily due to the 2007 recognition of non-deductible deferred compensation.

Capital Commitments, Capital Resources, and Liquidity

Capital commitments. Our primary uses of 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 related to development, exploitation, and exploration activities for the periods indicated:

	Year Ended December 31, 2009	2008 (In thousands)	2007
Development and exploitation	$ 121,259	$ 362,609	$ 270,161
Exploration	165,683	256,437	97,453
Total	$ 286,942	$ 619,046	$ 367,614

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 2009

ENCORE ACQUISITION COMPANY

yielded 57 gross (25.9 net) productive wells and one gross (1.0 net) dry holes. Our exploration expenditures primarily relate to drilling exploratory wells, seismic costs, delay rentals, and geological and geophysical costs. Our exploration capital for 2009 yielded 55 gross (16.4 net) productive wells and 7 gross (5.6 net) dry holes. Please read Items 1 and 2. Business and Properties Development Results for a description of the areas in which we drilled wells during 2009.

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

	Year Ended December 31,		
	2009	2008	2007
		(In thousands)	
Acquisitions of proved property	$ 402,457	$ 28,840	$ 796,239
Acquisitions of leasehold acreage	17,087	128,635	52,306
Total	$ 419,544	$ 157,475	$ 848,545

In August 2009, we acquired certain oil and natural gas properties from EXCO for approximately $357.4 million in cash (including a deposit of $37.5 million made in June 2009). In May 2009, ENP acquired certain natural gas properties in the Vinegarone Field in Val Verde County, Texas from an independent energy company for approximately $27.5 million in cash. In April 2007, we acquired oil and natural gas properties in the Williston Basin for approximately $392.1 million. In March 2007, we and ENP acquired oil and natural gas properties in the Big Horn Basin, including properties in the Elk Basin and the Gooseberry fields, for approximately $393.6 million.

During 2009, our capital expenditures for leasehold acreage related to the acquisition of unproved acreage in various areas. During 2008, $45.2 million of our capital expenditures for leasehold acreage related to the exercise of preferential rights in the Haynesville area and the remainder related to the acquisition of unproved acreage in various areas. During 2007, $16.1 million of our capital expenditures for leasehold acreage related to the Williston Basin asset acquisition and the remainder related to the acquisition of unproved acreage in various areas.

Funding of working capital. As of December 31, 2009 and 2008, our working capital (defined as total current assets less total current liabilities) was a negative $62.9 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 oil prices at December 31, 2009 as compared to December 31, 2008, which negatively impacted the fair value of our outstanding oil derivative contracts.

For 2010, we expect working capital to remain negative primarily due to the fair value of our outstanding commodity derivative contracts. 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 production volumes, our operating cash flow should remain positive in 2010.

Our capital 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 borrowings under our revolving credit facility.

Table of Contents

ENCORE ACQUISITION COMPANY

Off-balance sheet arrangements. We have no investments in unconsolidated entities or persons that could materially affect our liquidity or the 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 provides our contractual obligations and commitments at December 31, 2009:

			Payments Due by Period			
Contractual Obligations and Commitments	**Maturity Date**	**Total**	**2010**	**2011 - 2012**	**2013 - 2014**	**Thereafter**
			(In thousands)			
.25% Senior Subordinated Notes(a)	4/15/2014	$ 192,188	$ 9,375	$ 18,750	$ 164,063	$
.0% Senior Subordinated Notes(a)	7/15/2015	408,000	18,000	36,000	36,000	318,000
.5% Senior Subordinated Notes(a)	5/1/2016	363,938	21,375	42,750	42,750	257,063
.25% Senior Subordinated Notes(a)	12/1/2017	237,000	10,875	21,750	21,750	182,625
evolving credit facilities(a)	3/7/2012	432,824	10,144	422,680		
ommodity derivative contracts(b)		85,029	48,804	36,225		
nterest rate swaps(c)		3,669	3,320	349		
apital lease obligations		1,281	466	815		
evelopment commitments(d)		48,026	48,026			
perating leases and commitments(e)		13,568	3,983	6,978	2,607	
sset retirement obligations(f)		192,912	1,517	3,034	3,668	184,693
otal		$ 1,978,435	$ 175,885	$ 589,331	$ 270,838	$ 942,381

(a) Includes principal and projected interest payments. Please read Note 7 of Notes to Consolidated Financial Statements included in Item 8. Financial Statements and Supplementary Data for additional information regarding our long-term debt.

(b) Represents net liabilities for commodity derivative contracts. With the exception of $48.8 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 7A. Quantitative and Qualitative Disclosures about Market Risk and Note 12 of Notes to Consolidated Financial Statements included in Item 8. Financial Statements and Supplementary Data 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 7A. Quantitative and Qualitative Disclosures about Market Risk and Note 12 of Notes to Consolidated Financial Statements included in Item 1. Financial Statements for additional information regarding our interest rate swaps.

(d)

Represents authorized purchases for work in process. Also at December 31, 2009, we had $167.2 million of authorized purchases not placed to vendors (authorized AFEs), which were not accrued and are excluded from the above table but are budgeted for and are expected to be made unless circumstances change.

(e) Includes office space and equipment obligations that have non-cancelable lease terms in excess of one year of $13.2 million and future minimum payments for other operating commitments of $0.4 million. Please read Note 4 of Notes to Consolidated Financial Statements included in Item 8. Financial Statements and Supplementary Data for additional information regarding our operating leases.

(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 5 of Notes to Consolidated Financial Statements included in Item 8. Financial Statements and Supplementary Data for additional information regarding our asset retirement obligations.

ENCORE ACQUISITION COMPANY

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 currently believe that we have been allocated sufficient pipeline capacity to move our crude oil production. However, there can be no assurance that we will be allocated sufficient pipeline capacity to move our crude oil production in the future. An expansion of the Enbridge Pipeline was completed in early 2008, which moved the total Rockies area pipeline takeaway closer to increasing production volumes and thereby provided greater stability to oil differentials in the area. An additional expansion of Enbridge Pipeline was completed in early 2010, bringing additional takeaway capacity to the region, but in spite of these increases in capacity, the Enbridge Pipeline continues to run at full capacity. The Enbridge pipeline is currently presenting a new proposal to further expand the line in anticipation of the continuing expected production increases from the Williston / Bakken region. However, any 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. The following table shows the relationship between oil and natural gas wellhead prices as a percentage of average NYMEX prices by quarter for 2009:

	First Quarter of 2009	**Second Quarter of 2009**	**Third Quarter of 2009**	**Fourth Quarter of 2009**
Average oil wellhead to NYMEX percentage	82%	92%	89%	89%
Average natural gas wellhead to NYMEX percentage	67%	105%	109%	112%

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 resulting in a price we were paid per Mcf under certain contracts to be higher than the average NYMEX price.

Capital resources

Cash flows from operating activities. Cash provided by operating activities increased $82.4 million from $663.2 million in 2008 to $745.7 million in 2009, primarily due to the monetization of certain of our 2009 oil derivative contracts in March 2009 and decreased settlements paid under our oil derivative contracts as a result of lower average oil prices in 2009 as compared to 2008, partially offset by a decrease in our production margin.

Table of Contents

ENCORE ACQUISITION COMPANY

Cash provided by operating activities increased $343.5 million from $319.7 million in 2007 to $663.2 million in 2008, primarily due to an increase in our production margin, partially offset by increased settlements on our commodity derivative contracts as a result of higher commodity prices in the first half of 2008.

Cash flows from investing activities. Cash used in investing activities increased $41.1 million from $728.3 million in 2008 to $769.4 million in 2009, primarily due to a $290.4 million increase in amounts paid to acquire oil and natural gas properties, namely our EXCO asset acquisition, partially offset by a $218.7 million decrease in amounts paid to develop oil and natural gas properties and a $32.2 million decrease in net advancements to working interest partners. During 2009, we collected $7.4 million (net of advancements) from ExxonMobil for their portion of costs incurred by us in drilling wells under the joint development agreement as compared to advancements of $24.8 million (net of collections) in 2007.

Cash used in investing activities decreased $201.3 million from $929.6 million in 2007 to $728.3 million in 2008, primarily due to a $706.0 million decrease in amounts paid for acquisitions of oil and natural gas properties and a $283.7 million decrease in proceeds received for the disposition of assets, partially offset by a $225.1 million increase in development of oil and natural gas properties. In 2007, we paid approximately $393.6 million in conjunction with the Big Horn Basin asset acquisition and approximately $392.1 million in conjunction with the Williston Basin asset acquisition. In 2007, we also completed the sale of certain oil and natural gas properties in the Mid-Continent for net proceeds of approximately $294.8 million. During 2008, we advanced $24.8 million (net of collections) to ExxonMobil for their portion of costs incurred by us in drilling wells under the joint development agreement as compared to advancements of $29.5 million (net of collections) in 2007.

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

During 2009, we received net cash of $35.7 million from financing activities, including $202.4 million of net proceeds from the issuance of our 9.5% Notes, $100.6 million of net proceeds from the issuance of EAC common stock, and $170.1 million of net proceeds from the issuance of ENP common units, partially offset by net repayments on revolving credit facilities of $315 million, payments for deferred commodity derivative contract premiums of $71.4 million, and ENP distributions to noncontrolling interests of $37.7 million. Net repayments decreased the outstanding borrowings under revolving credit facilities from $725 million at December 31, 2008 to $410 million at December 31, 2009.

In December 2007, we announced that the Board approved a share repurchase program authorizing us to repurchase up to $50 million of our common stock. During 2008, we completed the share repurchase program by repurchasing and retiring 1,397,721 shares of our outstanding common stock at an average price of approximately $35.77 per share.

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 December 31, 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 2009, we did not repurchase any shares of our outstanding common stock under the share repurchase program. As of

December 31, 2009, approximately $22.8 million of our common stock remained authorized for repurchase.

During 2008, we received net cash of $65.4 million from financing activities, including net borrowings on our revolving credit facilities of $199 million, which resulted in an increase in outstanding borrowings under our revolving credit facilities from $526 million at December 31, 2007 to $725 million at December 31, 2008.

ENCORE ACQUISITION COMPANY

During 2007, we received net cash of $610.8 million from financing activities, including net borrowings on our revolving credit facilities of $458 million and net proceeds of $193.5 million from the issuance of ENP common units. Net borrowings on our revolving credit facilities were primarily due to borrowings used to finance our Big Horn Basin and Williston Basin asset acquisitions, which were partially offset by repayments from the net proceeds received from the Mid-Continent asset disposition and ENP s issuance of common units.

Liquidity

Our primary sources of liquidity are internally generated cash flows and the borrowing capacity under our revolving credit facility. We also have the ability to adjust our 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 currently do not believe it will result in any required prepayments of indebtedness.

Issuance of 9.5% Senior Subordinated Notes Due 2016. In April 2009, we issued $225 million of our 9.5% Notes at 92.228 percent of par value. We used the net proceeds of approximately $202.4 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 2009, our average realized oil and natural gas prices decreased by 39 percent and 55 percent, respectively, as compared to 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, cash flows from operations, and 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 7A. Quantitative and Qualitative Disclosures about Market Risk and Note 12 of Notes to Consolidated Financial Statements included in Item 8. Financial Statements and Supplementary Data for additional information regarding our commodity derivative contracts.

Revolving credit facilities. The syndicate of lenders underwriting our revolving credit facility includes 30 banking and other financial institutions, and the syndicate of lenders underwriting ENP s revolving credit facility includes 15 banking and other financial institutions. None of the lenders are underwriting more than ten 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.

Certain of the lenders underwriting our facility are also counterparties to our commodity derivative contracts. Please read Item 7A. Quantitative and Qualitative Disclosures About Market Risk for additional discussion.

Encore Acquisition Company 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. In March 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.

Table of Contents

ENCORE ACQUISITION COMPANY

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 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 April 2009, the borrowing base was reduced by $75 million as a result of our issuance of the 9.5% Notes. The reductions in the borrowing base under the EAC Credit Agreement did not result in any required prepayments of indebtedness. In December 2009, we amended the EAC Credit Agreement to, among other things, increase the borrowing base under the EAC Credit Agreement to $925 million. As of December 31, 2009, the borrowing base was $925 million.

We incur a commitment fee on the unused portion of the EAC Credit Agreement determined based on the ratio of outstanding borrowings 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 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%

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, 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) 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 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 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 including, among others, the following:

- 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;

ENCORE ACQUISITION COMPANY

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; 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 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 December 31, 2009 and February 17, 2010, there were $155 million of outstanding borrowings, $0.3 million of outstanding letters of credit, and $769.7 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. In March 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. In August 2009, OLLC amended the OLLC Credit Agreement to, among other things, (1) increase the borrowing base from $240 million to $375 million, (2) increase the aggregate commitments of the lenders from $300 million to $475 million, and (3) increase the interest rate margins and commitment fees applicable to loans made under the OLLC Credit Agreement. In November 2009, OLLC amended the OLLC Credit Agreement, which will be effective upon the closing of the Merger, to, among other things, permit the consummation of the Merger from being a Change of Control 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 $475 million. Availability under the OLLC Credit Agreement is subject to a borrowing base, which is redetermined semi-annually and upon requested special redeterminations. As of December 31, 2009, the borrowing base was $375 million.

OLLC incurs a commitment fee of 0.5 percent on the unused portion of the OLLC Credit Agreement.

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, 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) outstanding borrowings in relation to the borrowing base and (2) whether the loan is a Eurodollar loan or a base rate loan.

Table of Contents

ENCORE ACQUISITION COMPANY

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 Outstanding Borrowings to Borrowing Base	Applicable Margin for Eurodollar Loans	Applicable Margin for Base Rate Loans
Less than .50 to 1	2.250%	1.250%
Greater than or equal to .50 to 1 but less than .75 to 1	2.500%	1.500%
Greater than or equal to .75 to 1 but less than .90 to 1	2.750%	1.750%
Greater than or equal to .90 to 1	3.000%	2.000%

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 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 including, among others, the following:

- 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 2.5 to 1.0 (the ENP Interest Coverage Ratio); and

- a requirement that ENP and OLLC maintain a ratio of consolidated funded 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.

ENCORE ACQUISITION COMPANY

As of December 31, 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 December 31, 2009
ENP Current Ratio	Minimum 1.0 to 1.0	5.1 to 1.0
ENP Interest Coverage Ratio	Minimum 2.5 to 1.0	10.7 to 1.0
ENP Leverage Ratio	Maximum 3.5 to 1.0	2.0 to 1.0

The following table shows the calculation of the ENP Current Ratio as of December 31, 2009 ($ in thousands):

ENP current assets	$ 48,248
Availability under the OLLC Credit Agreement	120,000
ENP consolidated current assets	$ 168,248
Divided by: ENP consolidated current liabilities	$ 32,690
ENP Current Ratio	5.1

The following table shows the calculation of the ENP Interest Coverage Ratio for the twelve months ended December 31, 2009 ($ in thousands):

ENP Consolidated EBITDA(a)	$ 116,732
Divided by: ENP consolidated net interest expense and letter of credit fees	$ 10,928
ENP Interest Coverage Ratio	10.7

(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 December 31, 2009 ($ in thousands):

ENP consolidated funded debt	$ 255,000
Divided by: ENP Consolidated Adjusted EBITDA(a)	$ 127,719
ENP Leverage Ratio	2.0

(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.

Table of Contents

ENCORE ACQUISITION COMPANY

The following table presents a calculation of ENP Consolidated EBITDA and ENP Consolidated Adjusted EBITDA for the twelve months ended December 31, 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.

ENP consolidated net income	$ (40,507)
ENP unrealized non-cash hedge gain	94,441
ENP consolidated net interest expense	10,928
ENP income and franchise taxes	14
ENP depletion, depreciation, amortization, and exploration expense	50,040
ENP non-cash unit-based compensation	565
ENP other non-cash	1,251
ENP Consolidated EBITDA	116,732
Pro forma effect of acquisitions	10,987
ENP Consolidated Adjusted EBITDA	$ 127,719

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 December 31, 2009, there were $255 million of outstanding borrowings and $120 million of borrowing capacity under the OLLC Credit Agreement. On February 17, 2010, there were $260 million of outstanding borrowings and $115 million of borrowing capacity under the OLLC Credit Agreement.

Indentures governing our senior subordinated notes. We and our restricted subsidiaries are subject to certain negative and financial covenants under the indentures governing the 9.5% Notes, the 6.25% Notes, the 6.0% Notes, and the 7.25% Notes (collectively, the Notes). The provisions of the indentures limit our and our restricted subsidiaries ability to, among other things:

- incur additional indebtedness;
- pay dividends on our capital stock or redeem, repurchase, or retire our capital stock or subordinated indebtedness;
- make investments;
- incur liens;

create any consensual limitation on the ability of our restricted subsidiaries to pay dividends, make loans, or transfer property to us;

engage in transactions with our affiliates;

sell assets, including capital stock of our subsidiaries;

consolidate, merge, or transfer assets;

a requirement that we maintain a current ratio (as defined in the indentures) of not less than 1.0 to 1.0; and

a requirement that we maintain a ratio of consolidated EBITDA (as defined in the indentures) to consolidated interest expense of not less than 2.5 to 1.0.

ENCORE ACQUISITION COMPANY

If we experience a change of control (as defined in the indentures), subject to certain conditions, we must give holders of the Notes the opportunity to sell to us their Notes at 101 percent of the principal amount, plus accrued and unpaid interest.

Capitalization. At December 31, 2009, we had total assets of $3.7 billion and total capitalization of $2.8 billion, of which 57 percent was represented by equity and 43 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.

Changes in Prices

Our oil and natural gas revenues, the value of our assets, and our ability to obtain bank loans or additional capital on attractive terms are affected by changes in oil and natural gas prices, which fluctuate significantly. The following table provides our average oil and natural gas prices for the periods indicated. Our average realized prices for 2008 and 2007 were decreased by $0.20 and $3.96 per BOE, respectively, as a result of commodity derivative contracts, which were previously designated as hedges.

	Year Ended December 31,		
	2009	**2008**	**2007**
Average realized prices:			
Oil ($/Bbl)	$ 54.85	$ 89.30	$ 58.96
Natural gas ($/Mcf)	3.87	8.63	6.26
Combined ($/BOE)	43.43	77.87	52.66
Average wellhead prices:			
Oil ($/Bbl)	$ 54.85	$ 89.58	$ 63.50
Natural gas ($/Mcf)	3.87	8.63	6.69
Combined ($/BOE)	43.43	78.07	56.62

Increases in oil and natural gas prices may be accompanied by or result in: (1) increased development costs, as the demand for drilling operations increases; (2) increased severance taxes, as we are subject to higher severance taxes due to the increased value of oil and natural gas extracted from our wells; (3) increased LOE, as the demand for services related to the operation of our wells increases; and (4) increased electricity costs. Decreases in oil and natural gas prices may be accompanied by or result in: (1) decreased development costs, as the demand for drilling operations decreases; (2) decreased severance taxes, as we are subject to lower severance taxes due to the decreased value of oil and natural gas extracted from our wells; (3) decreased LOE, as the demand for services related to the operation of our wells decreases; (4) decreased electricity costs; (5) impairment of oil and natural gas properties; and (6) decreased revenues and cash flows. We believe our risk management program and available borrowing capacity under our revolving credit facility provide means for us to manage commodity price risks.

Critical Accounting Policies and Estimates

Preparing financial statements in accordance with GAAP requires management to make estimates and assumptions that affect reported amounts of assets, liabilities, revenues, and expenses, and related disclosures. Management considers an accounting estimate to be critical if it requires assumptions to be made that were uncertain at the time the estimate was made, and changes in the estimate or different estimates that could have been selected, could have a material impact on our consolidated results of operations or financial condition. Management has identified the following critical accounting policies and estimates.

ENCORE ACQUISITION COMPANY

Oil and Natural Gas Properties

Successful efforts method. We use the successful efforts method of accounting for oil and natural gas properties under ASC 932 (formerly SFAS No. 19, *Financial Accounting and Reporting by Oil and Gas Producing Companies*). Under this method, all costs associated with productive and nonproductive development wells are capitalized. Exploration expenses, including geological and geophysical expenses and delay rentals, are charged to expense as incurred. Costs associated with drilling exploratory wells are initially capitalized pending determination of whether the well is economically productive or nonproductive.

If an exploratory well does not find reserves or does not find reserves in a sufficient quantity as to make them economically producible, the previously capitalized costs are expensed in the period in which the determination is made. If an exploratory well finds reserves but they cannot be classified as proved, we continue to capitalize the associated cost as long as the well has found a sufficient quantity of reserves to justify its completion as a producing well and we are making sufficient progress in assessing the reserves and the operating viability of the project. If subsequently it is determined that these conditions do not continue to exist, all previously capitalized costs associated with the exploratory well are expensed in the period in which the determination was made. Re-drilling or directional drilling in a previously abandoned well is classified as development or exploratory based on whether it is in a proved or unproved reservoir. Costs for repairs and maintenance to sustain or increase production from the existing producing reservoir are charged to expense as incurred. Costs to recomplete a well in a different unproved reservoir are capitalized pending determination that economic reserves have been added. If the recompletion is unsuccessful, the costs are charged to expense.

DD&A expense is directly affected by our reserve estimates. Significant revisions to reserve estimates can be and are made by our reserve engineers each year. Mostly these are the result of changes in price, but as reserve quantities are estimates, they can also change as more or better information is collected, especially in the case of estimates in newer fields. Downward revisions have the effect of increasing our DD&A rate, while upward revisions have the effect of decreasing our DD&A rate. Assuming no other changes, such as an increase in depreciable base, as our reserves increase, the amount of DD&A expense in a given period decreases and vice versa. DD&A expense associated with lease and well equipment and intangible drilling costs is based upon proved developed reserves, while DD&A expense for capitalized leasehold costs is based upon total proved reserves. As a result, changes in the classification of our reserves could have a material impact on our DD&A expense.

Miller and Lents estimates our reserves annually at December 31. This results in a new DD&A rate which we use for the preceding fourth quarter after adjusting for fourth quarter production. We internally estimate reserve additions and reclassifications of reserves from proved undeveloped to proved developed at the end of the first, second, and third quarters for use in determining a DD&A rate for the respective quarter.

Significant tangible equipment added or replaced that extends the useful or productive life of the property is capitalized. Costs to construct facilities or increase the productive capacity from existing reservoirs are capitalized. Internal costs directly associated with the development of proved properties are capitalized as a cost of the property and are classified accordingly in our consolidated financial statements. Capitalized costs are amortized on a unit-of-production basis over the remaining life of proved developed reserves or total proved reserves, as applicable. Natural gas volumes are converted to BOE at the rate of six Mcf of natural gas to one Bbl of oil.

The costs of retired, sold, or abandoned properties that constitute part of an amortization base are charged or credited, net of proceeds received, to accumulated DD&A.

In accordance with ASC 360-10, 205, 840, 958, and 855-10-60-1 (formerly SFAS No. 144, *Accounting for the Impairment or Disposal of Long-Lived Assets*), we assess the need for an impairment of long-lived assets to be held and used, including proved oil and natural gas properties, whenever events and circumstances indicate that the carrying value of the asset may not be recoverable. If impairment is indicated based on a comparison of the asset s carrying value to its undiscounted expected future net cash flows, then an

ENCORE ACQUISITION COMPANY

impairment charge is recognized to the extent the asset s carrying value exceeds its fair value. Expected future net cash flows are based on existing proved reserves (and appropriately risk-adjusted probable reserves), forecasted production information, and management s outlook of future commodity prices. Any impairment charge incurred is expensed and reduces our net basis in the asset. Management aggregates proved property for impairment testing the same way as for calculating DD&A. The price assumptions used to calculate undiscounted cash flows is based on judgment. We use prices consistent with the prices we believe a market participant would use in bidding on acquisitions and/or assessing capital projects. These price assumptions are critical to the impairment analysis as lower prices could trigger impairment.

Unproved properties, the majority of which relate to the acquisition of leasehold interests, are assessed for impairment on a property-by-property basis for individually significant balances and on an aggregate basis for individually insignificant balances. If the assessment indicates impairment, a loss is recognized by providing a valuation allowance at the level at which impairment was assessed. The impairment assessment is affected by economic factors such as the results of exploration activities, commodity price outlooks, remaining lease terms, and potential shifts in business strategy employed by management. In the case of individually insignificant balances, the amount of the impairment loss recognized is determined by amortizing the portion of the unproved properties costs which we believe will not be transferred to proved properties over the life of the lease. One of the primary factors in determining what portion will not be transferred to proved properties is the relative proportion of the unproved properties on which proved reserves have been found in the past. Since the wells drilled on unproved acreage are inherently exploratory in nature, actual results could vary from estimates especially in newer areas in which we do not have a long history of drilling.

Oil and natural gas reserves. Our estimates of proved reserves are based on the quantities of oil and natural gas, which, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be economically producible from a given date forward from known reservoirs under existing conditions and operating methods. Miller and Lents prepares a reserve and economic evaluation of all of our properties on a well-by-well basis. Assumptions used by Miller and Lents in calculating reserves or regarding the future cash flows or fair value of our properties are subject to change in the future. The accuracy of reserve estimates is a function of the:

- quality and quantity of available data;
- interpretation of that data;
- accuracy of various mandated economic assumptions; and
- judgment of the independent reserve engineer.

Future prices received for production and future production costs may vary, perhaps significantly, from the prices and costs assumed for purposes of calculating reserve estimates. We may not be able to develop proved reserves within the periods estimated. Furthermore, prices and costs may not remain constant. Actual production may not equal the estimated amounts used in the preparation of reserve projections. As these estimates change, calculated reserves change. Any change in reserves directly impacts our estimate of future cash flows from the property, the property s fair value, and our DD&A rate.

Asset retirement obligations. In accordance with ASC 410-20, 450-20, 835-20, 360-10-35, 840-10, and 980-410 (formerly SFAS No. 143, *Accounting for Asset Retirement Obligations*), we recognize the fair value of a liability for an asset retirement obligation in the period in which the liability is incurred. For oil and natural gas properties, this is the period in which an oil or natural gas property is acquired or a new well is drilled. An amount equal to and offsetting the liability is capitalized as part of the carrying amount of our oil and natural gas properties. The liability is recorded at its discounted risk adjusted fair value and then accreted each period until it is settled or the asset is sold, at which time the liability is reversed.

The fair value of the liability associated with the asset retirement obligation is determined using significant assumptions, including current estimates of the plugging and abandonment costs, annual expected

ENCORE ACQUISITION COMPANY

inflation of these costs, the productive life of the asset, and our credit-adjusted risk-free interest rate used to discount the expected future cash flows. Changes in any of these assumptions can result in significant revisions to the estimated asset retirement obligation. Revisions to the obligation are recorded with an offsetting change to the carrying amount of the related oil and natural gas properties, resulting in prospective changes to DD&A and accretion expense. Because of the subjectivity of assumptions and the relatively long life of most of our oil and natural gas properties, the costs to ultimately retire these assets may vary significantly from our estimates.

Goodwill and Other Intangible Assets

We account for goodwill and other intangible assets under the provisions of ASC 350, 730-10-60-3, 323-10-35-13, 205-20-60-4, and 280-10-60-2 (formerly SFAS No. 142, *Goodwill and Other Intangible Assets*). Goodwill represents the excess of the purchase price over the estimated fair value of the net assets acquired in business combinations. Goodwill is assessed for impairment annually on December 31 or whenever indicators of impairment exist. The goodwill test is performed at the reporting unit level. We have determined that we have two reporting units: EAC Standalone and ENP. If indicators of impairment are determined to exist, an impairment charge is recognized for the amount by which the carrying value of goodwill exceeds its implied fair value.

We utilize both a market capitalization and an income approach to determine the fair value of our reporting units. The primary component of the income approach is the estimated discounted future net cash flows expected to be recovered from the reporting unit s oil and natural gas properties. Our analysis concluded that there was no impairment of goodwill as of December 31, 2009. Significant decreases in the prices of oil and natural gas or significant negative reserve adjustments from the December 31, 2009 assessment could change our estimates of the fair value of our reporting units and could result in an impairment charge.

Intangible assets with definite useful lives are amortized over their estimated useful lives. In accordance with ASC 360-10, 205, 840, 958, and 855-10-60-1, we evaluate the recoverability of intangible assets with definite useful lives whenever events or changes in circumstances indicate that the carrying value of the asset may not be fully recoverable. An impairment loss exists when the estimated undiscounted cash flows expected to result from the use of the asset and its eventual disposition are less than its carrying amount.

We allocate the purchase price paid for the acquisition of a business to the assets and liabilities acquired based on the estimated fair values of those assets and liabilities. Estimates of fair value are based upon, among other things, reserve estimates, anticipated future prices and costs, and expected net cash flows to be generated. These estimates are often highly subjective and may have a material impact on the amounts recorded for acquired assets and liabilities.

Net Profits Interests

A major portion of our acreage position in the CCA is subject to net profits interests ranging from one percent to 50 percent. The holders of these net profits interests are entitled to receive a fixed percentage of the cash flow remaining after specified costs have been subtracted from net revenue. The net profits calculations are contractually defined. In general, net profits are determined after considering costs associated with production, overhead, interest, and development. The amounts of reserves and production attributable to net profits interests are deducted from our reserves and production data, and our revenues are reported net of net profits interests. The reserves and production attributed to the net profits interests are calculated by dividing estimated future net profits interests (in the case of reserves) or prior period actual net profits interests (in the case of production) by commodity prices at the determination date. Fluctuations in commodity prices and the levels of development activities in the CCA from period to period will impact the reserves and production attributed to the net profits interests and will have an inverse effect on our oil and natural gas revenues, production, reserves, and net income.

ENCORE ACQUISITION COMPANY

Oil and Natural Gas Revenue Recognition

Oil and natural gas revenues are recognized as oil and natural gas is produced and sold, net of royalties and net profits interests. Royalties, net profits interests, and severance taxes are incurred based upon the actual price received from the sales. To the extent actual volumes and prices of oil and natural gas sales are unavailable for a given reporting period because of timing or information not received from third parties, the expected sales volumes and prices for those properties are estimated and recorded. Natural gas revenues are reduced by any processing and other fees incurred except for transportation costs paid to third parties, which are recorded as expense. Natural gas revenues are recorded using the sales method of accounting whereby revenue is recognized based on actual sales of natural gas rather than our proportionate share of natural gas production. If our overproduced imbalance position (i.e., we have cumulatively been over-allocated production) is greater than our share of remaining reserves, a liability is recorded for the excess at period-end prices unless a different price is specified in the contract in which case that price is used. Revenue is not recognized for production in tanks, oil marketed on behalf of joint interest owners in our properties, or oil in pipelines that has not been delivered to the purchaser.

Income Taxes

Our effective tax rate is subject to variability from period to period as a result of factors other than changes in federal and state tax rates and/or changes in tax laws which can affect taxpaying companies. Our effective tax rate is affected by changes in the allocation of property, payroll, and revenues between states in which we own property as rates vary from state to state. Our deferred taxes are calculated using rates we expect to be in effect when they reverse. As the mix of property, payroll, and revenues varies by state, our estimated tax rate changes. Due to the size of our gross deferred tax balances, a small change in our estimated future tax rate can have a material effect on earnings.

Derivatives

We use 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 our exposure to commodity price decreases, but they can also limit the benefit we might otherwise receive from commodity price increases. Our risk management activity is generally accomplished through over-the-counter derivative contracts with large financial institutions. We also use derivative instruments in the form of interest rate swaps, which hedge risk related to interest rate fluctuation.

We apply the provisions of ASC 815 (formerly SFAS No. 133, *Accounting for Derivative Instruments and Hedging Activities*), 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, the effective portion of changes in fair value can be recognized in accumulated other comprehensive income or 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.

We have elected to designate our outstanding 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 income or loss in equity 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 immediately in earnings. While management does not anticipate changing the designation of our interest rate swaps as hedges, factors beyond our control can preclude the use of hedge accounting.

We have not elected to designate our current portfolio of commodity derivative contracts as hedges. Therefore, changes in fair value of these derivative instruments are recognized in earnings each period.

ENCORE ACQUISITION COMPANY

Please read Item 7A. Quantitative and Qualitative Disclosures About Market Risk for discussion regarding our sensitivity analysis for financial instruments.

New Accounting Pronouncements

FASB Launches Accounting Standards Codification

In June 2009, the FASB issued ASC 105-10 (formerly SFAS No. 168, *The FASB Accounting Standards Codification and the Hierarchy of Generally Accepted Accounting Principles*). ASC 105-10 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. ASC 105-10 was prospectively effective for financial statements issued for fiscal years ending on or after September 15, 2009, and interim periods within those fiscal years. The adoption of ASC 105-10 on July 1, 2009 did not impact our results of operations or financial condition.

Following the Codification, the FASB does not issue new standards in the form of Statements, FASB Staff Positions (FSP), or EITF Abstracts. Instead, it issues Accounting Standards Updates (ASU), which update the Codification, provide background information about the guidance, and provide the basis for conclusions on the changes to the Codification.

The Codification did not change GAAP; however, it did change the way GAAP is organized and presented. As a result, these changes impact how companies, including us, reference GAAP in their financial statements and in their significant accounting policies.

ASC 820-10 (formerly FSP No. FAS 157-2, Effective Date of FASB Statement No. 157)

In February 2008, the FASB issued ASC 820-10, which delayed the effective date of ASC 820-10 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). ASC 820-10 was prospectively effective for financial statements issued for fiscal years beginning after November 15, 2008, and interim periods within those fiscal years. We elected a partial deferral of ASC 820-10 for all instruments within the scope of ASC 820-10, including, but not limited to, our asset retirement obligations and indefinite lived assets. The adoption of ASC 820-10 on January 1, 2009 as it relates to nonfinancial assets and liabilities did not have a material impact on our results of operations or financial condition.

ASC 805 (formerly SFAS No. 141 (revised 2007), Business Combinations)

In December 2007, the FASB issued ASC 805, which 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 ASC 805-20 (formerly FSP No. FAS 141(R)-1, *Accounting for Assets Acquired and Liabilities Assumed in a Business Combination That Arises from Contingencies*), which amends and clarifies ASC 805 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. ASC 805 and ASC 805-20 were prospectively effective for business combinations consummated in fiscal years beginning on or after December 15, 2008. The application of ASC 805 and ASC 805-20 to the acquisition of certain oil and natural gas properties and related assets in the Mid-Continent and East Texas resulted in the expensing of approximately $1.5 million of transaction costs.

ENCORE ACQUISITION COMPANY

ASC 810-10-65-1 (formerly SFAS No. 160, Noncontrolling Interests in Consolidated Financial Statements an amendment to ARB No. 51)

In December 2007, the FASB issued ASC 810-10-65-1, which establishes accounting and reporting standards for the noncontrolling interest in a subsidiary and for the deconsolidation of a subsidiary. ASC 810-10-65-1 was prospectively effective for financial statements issued for fiscal years beginning on or after December 15, 2008, except for the presentation and disclosure requirements which were retrospectively effective. ASC 810-10-65-1 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, ASC 810-10-65-1 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 or losses on a subsidiaries issuance of equity to be accounted for as capital transactions. The adoption of ASC 810-10-65-1 on January 1, 2009 did not have a material impact on our results of operations or financial condition. The retrospective application of ASC 810-10-65-1 resulted in the reclassification of approximately $169.1 million from Minority interest in consolidated partnership to Noncontrolling interest at December 31, 2008 on our consolidated balance sheet.

ASC 815-10 (formerly SFAS No. 161, Disclosures about Derivative Instruments and Hedging Activities an amendment of FASB Statement No. 133)

In March 2008, the FASB issued ASC 815-10, which requires enhanced disclosures: including (1) how and why an entity uses derivative instruments; (2) how derivative instruments and related hedged items are accounted for under ASC 815; and (3) how derivative instruments and related hedged items affect an entity s financial position, financial performance, and cash flows. ASC 815-10 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 ASC 815-10 on January 1, 2009 required additional disclosures regarding our derivative instruments; however, it did not impact our results of operations or financial condition.

ASC 260-10 (formerly FSP No. EITF 03-6-1, Determining Whether Instruments Granted in Share-Based Payment Transactions Are Participating Securities)

In June 2008, the FASB issued ASC 260-10, which addresses whether instruments granted in share-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 under the two-class method. ASC 260-10 was retroactively effective for financial statements issued for fiscal years beginning after December 15, 2008, and interim periods within those years. In this Report, periods prior to the adoption of ASC 260-10 have been restated to calculate earnings per share in accordance with this pronouncement. The retrospective application of ASC 260-10 reduced our basic earnings per share by $0.14 for 2008 and reduced our diluted earnings per share by $0.06 and $0.01 for 2008 and 2007, respectively. The adoption of ASC 260-10 did not have an impact on our basic earnings per share for 2007.

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

ENCORE ACQUISITION COMPANY

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 was prospectively effective for financial statements issued for fiscal years ending on or after December 31, 2009.

ASC 855-10 (formerly SFAS No. 165, Subsequent Events)

In June 2009, the FASB issued ASC 855-10 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, ASC 855-10 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. ASC 855-10 was prospectively effective for financial statements issued for interim or annual periods ending after June 15, 2009. The adoption of ASC 855-10 on June 30, 2009 did not impact our results of operations or financial condition.

ASU No. 2009-05, Fair Value Measurement and Disclosure: Measuring Liabilities at Fair Value (ASU 2009-05)

In August 2009, the FASB issued ASU 2009-05 to provide clarification on measuring liabilities at fair value when a quoted price in an active market is not available. In particular, ASU 2009-05 specifies that a valuation technique should be applied that used either the quote of the liability when traded as an asset, the quoted prices for similar liabilities or similar liabilities when traded as assets, or another valuation technique consistent with existing fair value measurement guidance. ASU 2009-05 was prospectively effective for financial statements issued for interim or annual periods ending after October 1, 2009. The adoption of ASU 2009-05 on December 31, 2009 did not impact our results of operations or financial condition.

ASU No. 2010-03, Oil and Gas Reserve Estimation and Disclosure (ASU 2010-03)

In January 2010, the FASB issued ASU 2010-03 to align the oil and natural gas reserve estimation and disclosure requirements of Extractive Activities Oil and Gas (ASC 932) with the requirements in the SEC s final rule, *Modernization of the Oil and Gas Reporting*. ASU 2010-03 was prospectively effective for financial statements issued for annual periods ending on or after December 31, 2009.

ASU No. 2010-06, Improving Disclosures about Fair Value Measurements (ASU 2010-06)

In January 2010, the FASB issued ASU 2010-06 to require additional information to be disclosed principally in respect of level 3 fair value measurements and transfers to and from Level 1 and Level 2 measurements; in addition, enhanced disclosure is required concerning inputs and valuation techniques used to determine Level 2 and Level 3 fair value measurements. ASU 2010-06 was generally effective for interim and annual reporting periods beginning after December 15, 2009; however, the requirements to disclose separately purchases, sales, issuances, and settlements in the Level 3 reconciliation are effective for fiscal years beginning after December 15, 2010 (and for interim periods within such years) with early adoption allowed. The adoption of ASU 2010-06 on December 31, 2009 did not impact our results of operations or financial condition.

Information Concerning Forward-Looking Statements

This Report contains forward-looking statements, which 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, inten believe, should, predict, potential, pursue, target,

71

ENCORE ACQUISITION COMPANY

continue, and other words and terms of similar meaning. In particular, forward-looking statements included in this Report relate to, among other things, the following:

- the occurrence of any event, change, or other circumstance that could affect the consummation of the Merger or give rise to the termination of the Merger Agreement in connection with the Merger;
- the inability to complete the Merger due to the failure to satisfy any conditions required to consummate the Merger;
- items of income and expense (including, without limitation, LOE, production taxes, DD&A, G&A, and effective income tax rates);
- expected capital expenditures and the focus of our capital program;
- areas of future growth;
- our development and exploitation programs;
- future secondary development and tertiary recovery potential;
- anticipated prices for oil and natural gas and expectations regarding differentials between wellhead prices and benchmark prices (including, without limitation, the effects of the worldwide economic recession);
- projected results of operations;
- timing and amount of future production of oil and natural gas;
- availability of pipeline capacity;
- expected commodity derivative positions and payments related thereto (including the ability of counterparties to fulfill obligations);
- expectations regarding working capital, cash flow, and liquidity;
- projected borrowings under our revolving credit facility (and the ability of lenders to fund their commitments); and
- the marketing of our oil and natural gas production.

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 this Report 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.

Except for our obligations to disclose material information under United States federal securities laws, we undertake no obligation to release publicly any revision to any forward-looking statement, to report events or circumstances after the date of this Report, or to report the occurrence of unanticipated events.

ITEM 7A. ***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

ENCORE ACQUISITION COMPANY

we view and manage our ongoing market risk exposures. We do not enter into market risk sensitive instruments for speculative trading purposes.

Derivative policy. Due to the volatility of crude oil and natural gas prices, we enter into various derivative instruments to manage and reduce our exposure to changes in the market price of crude oil and natural gas. We use options (including floors and collars) and fixed price swaps to mitigate the impact of downward swings in prices. All contracts are settled with cash and do not require the delivery of physical volumes to satisfy settlement. While this strategy may result in us having lower net cash inflows in times of higher oil and natural gas prices than we would otherwise have, had we not utilized these instruments, management believes that the resulting reduced volatility of cash flow is beneficial.

Counterparties. At December 31, 2009, we had committed 10 percent or greater (in terms of fair market value) of either our oil or natural gas derivative contracts in asset positions to the following counterparties:

Counterparty	Fair Market Value of Oil Derivative Contracts Committed	Fair Market Value of Natural Gas Derivative Contracts Committed
	(In thousands)	
BNP Paribas	$ 22,570	$ 7,496
Calyon	(a)	8,550
JP Morgan	10,272	(a)
Royal Bank of Canada	14,059	(a)
Wachovia	8,302	3,844

(a) Less than 10 percent.

In order to mitigate the credit risk of financial instruments, we enter into master netting agreements with certain counterparties. The master netting agreement is a standardized, bilateral contract between a given counterparty and us. Instead of treating each derivative financial transaction between the counterparty and us separately, the master netting agreement enables the counterparty and us to aggregate all financial trades and treat them as a single agreement. This arrangement is intended to benefit us in three ways: (1) the netting of the value of all trades reduces the likelihood of counterparties requiring daily collateral posting by us; (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 our credit exposure to a given counterparty in the event of close-out.

Commodity price sensitivity. We manage 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, we enter into floor spreads. In a floor spread, we purchase puts at a specified price (a purchased put) and also sells a put at a lower price (a short put). This strategy enables us to achieve some downside protection for a portion of our 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 we have protection against additional 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, we purchased oil put options for 2,000 Bbls/D in 2010 at $65 per Bbl. As NYMEX prices increased in 2008, we wanted to protect downside price exposure at the higher price. In order to do this, we purchased oil put options for 2,000 Bbls/D in 2010 at $75 per Bbl and simultaneously sold oil put options for 2,000 Bbls/D in 2010 at $65 per Bbl. Thus, after these transactions were completed, we had purchased two oil put options for 2,000 Bbls/D in 2010 (one

Table of Contents

ENCORE ACQUISITION COMPANY

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 us 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 our other floor contracts.

The counterparties to our commodity derivative contracts are a diverse group of six institutions, all of which are currently rated A+ or better by Standard & Poor s and/or Fitch. As of December 31, 2009, the fair market value of our oil derivative contracts was a net liability of approximately $18.2 million and the fair market value of our natural gas derivative contracts was a net asset of approximately $19.0 million. These amounts exclude deferred premiums of $48.8 million that are not subject to changes in commodity prices. Based on our open commodity derivative positions at December 31, 2009, a 10 percent increase in the respective NYMEX prices for oil and natural gas would decrease our net commodity derivative asset by approximately $82.8 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 $85.4 million.

The following tables summarize our open commodity derivative contracts as of December 31, 2009:

Oil Derivative Contracts

Period	Average Daily Floor Volume	Weighted Average Floor Price	Average Daily Cap Volume	Weighted Average Cap Price	Average Daily Swap Volume	Weighted Average Swap Price	Asset/ (Liability) Fair Market Value
	(Bbls)	(per Bbl)	(Bbls)	(per Bbl)	(Bbls)	(per Bbl)	(In thousands)
2010							$ (30,760)
	880	$ 80.00	2,940	$ 90.57		$	
	5,500	73.47	3,000	74.13	3,885	77.79	
	8,385	62.83	500	65.60	1,750	64.08	
	1,000	56.00			1,000	59.70	
2011							17,720
	4,880	80.00	2,940	94.44	325	80.00	
	2,500	70.00			1,060	78.42	
	4,385	65.00			250	69.65	
2012							(5,120)
	750	70.00	500	82.05	835	81.19	
	2,135	65.00	250	79.25	1,300	76.54	
							$ (18,160)

Table of Contents

ENCORE ACQUISITION COMPANY

Natural Gas Derivative Contracts

Period	Average Daily Floor Volume (Mcf)	Weighted Average Floor Price (per Mcf)	Average Daily Cap Volume (Mcf)	Weighted Average Cap Price (per Mcf)	Average Daily Swap Volume (Mcf)	Weighted Average Swap Price (per Mcf)	Asset Fair Market Value (In thousands)
Jan. June 2010							$ 5,949
	3,800	$ 8.20	3,800	$ 9.58	25,452	$ 6.46	
	4,698	7.26			20,550	5.23	
July Dec. 2010							6,644
	3,800	8.20	3,800	9.58			
	4,698	7.26	10,000	6.25	25,452	6.46	
	10,000	5.13			550	5.86	
2011							4,677
	3,398	6.31			27,952	6.48	
					550	5.86	
2012							1,755
	898	6.76			25,452	6.47	
					550	5.86	
							$ 19,025

Interest rate sensitivity. At December 31, 2009, we had total long-term debt of $1.2 billion, net of discount of $20.9 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 $410 million as of December 31, 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 $1.0 million of interest expense per year on our revolving credit facilities, and if the Eurodollar rate decreased by 10 percent, we would incur 1.0 million less. Additionally, if the discount or premium rates on our senior subordinated notes increased by 10 percent, the fair value of our fixed rate debt at December 31, 2009 would increase from approximately $828.8 million to approximately $829.8 million, and if the discount or premium rates decreased by 10 percent, the fair value would decrease to approximately $827.7 million.

ENP manages interest rate risk with interest rate swaps whereby it swaps floating rate debt under the OLLC Credit Agreement with a weighted average fixed rate. As of December 31, 2009, the fair market value of ENP s interest rate swaps was a net liability of approximately $3.7 million. If the Eurodollar rate increased by 10 percent, the fair value would decrease to approximately $3.4 million, and if the Eurodollar rate decreased by 10 percent, the fair value would increase to approximately $3.9 million.

The following table summarizes ENP s open interest rate swaps as of December 31, 2009:

Term		Notional Amount (In thousands)	Fixed Rate	Floating Rate
Jan. 2010	Jan. 2011	$ 50,000	3.1610%	1-month LIBOR
Jan. 2010	Jan. 2011	25,000	2.9650%	1-month LIBOR
Jan. 2010	Jan. 2011	25,000	2.9613%	1-month LIBOR
Jan. 2010	Mar. 2012	50,000	2.4200%	1-month LIBOR

ENCORE ACQUISITION COMPANY

ITEM 8. *FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA*

Index to Consolidated Financial Statements

Table of Contents

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors and Stockholders of
Encore Acquisition Company:

We have audited the accompanying consolidated balance sheets of Encore Acquisition Company (the Company) as of December 31, 2009 and 2008, and the related consolidated statements of operations, equity and comprehensive income (loss), and cash flows for each of the three years in the period ended December 31, 2009. These financial statements are the responsibility of the Company s management. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, the financial statements referred to above present fairly, in all material respects, the consolidated financial position of Encore Acquisition Company at December 31, 2009 and 2008, and the consolidated results of its operations and its cash flows for each of the three years in the period ended December 31, 2009, in conformity with U.S. generally accepted accounting principles.

As discussed in Note 2 to the consolidated financial statements, effective January 1, 2009, the Company retroactively changed its method for the presentation of noncontrolling interests in consolidated subsidiaries with the adoption of the guidance originally issued in FASB Statement No. 160, *Noncontrolling Interests in Consolidated Financial Statements an amendment to ARB No. 51* (codified in FASB ASC Topic 810, *Consolidation*) and retroactively changed its method of calculating basic and diluted earnings per share with the adoption of the guidance originally issued in FSP No. EITF 03-6-1, *Determining Whether Instruments Granted in Share-Based Payment Transactions Are Participating Securities* (codified in FASB ASC Topic 260, *Earnings Per Share*). Additionally, as discussed in Note 2 to the consolidated financial statements, the Company has changed its reserve estimates and related disclosures as a result of adopting new oil and gas reserve estimation and disclosure requirements resulting from Accounting Standards Update No. 2010-03*, Oil and Gas Reserve Estimation and Disclosures,* effective for annual reporting periods ended on or after December 31, 2009.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), Encore Acquisition Company s internal control over financial reporting as of December 31, 2009, based on criteria established in *Internal Control Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission and our report dated February 24, 2010 expressed an unqualified opinion thereon.

/s/ Ernst & Young LLP

Fort Worth, Texas
February 24, 2010

Table of Contents

ENCORE ACQUISITION COMPANY

CONSOLIDATED BALANCE SHEETS

	December 31, 2009	December 31, 2008
	(In thousands, except share and par value amounts)	
ASSETS		
Current assets:		
Cash and cash equivalents	$ 13,958	$ 2,039
Accounts receivable, net of allowance for doubtful accounts of $434 and $381, respectively	114,872	117,995
Current portion of long-term receivables	10,581	11,070
Inventory	26,674	24,798
Derivatives	25,825	349,344
Income taxes	1,712	29,445
Other	3,897	6,239
Total current assets	197,519	540,930
Properties and equipment, at cost successful efforts method:		
Proved properties, including wells and related equipment	4,204,622	3,538,459
Unproved properties	95,601	124,339
Accumulated depletion, depreciation, and amortization	(1,058,267)	(771,564)
	3,241,956	2,891,234
Other property and equipment	32,649	25,192
Accumulated depreciation	(17,187)	(12,753)
	15,462	12,439
Goodwill	60,606	60,606
Derivatives	35,206	38,497
Long-term receivables, net of allowance for doubtful accounts of $13,645 and $7,643, respectively	55,358	60,915
Other	57,854	28,574
Total assets	$ 3,663,961	$ 3,633,195
LIABILITIES AND EQUITY		
Current liabilities:		
Accounts payable	$ 7,138	$ 10,017

Accrued liabilities:		
Lease operating	15,862	19,108
Development capital	47,892	79,435
Interest	15,836	11,808
Production, ad valorem, and severance taxes	29,735	25,133
Compensation	12,991	16,216
Derivatives	69,958	63,476
Oil and natural gas revenues payable	18,415	10,821
Deferred taxes	18,689	105,768
Other	23,857	10,470
Total current liabilities	260,373	352,252
Derivatives	42,698	8,922
Future abandonment cost, net of current portion	52,367	48,058
Deferred taxes	453,110	416,915
Long-term debt	1,214,097	1,319,811
Other	10,483	3,989
Total liabilities	2,033,128	2,149,947
Commitments and contingencies (see Note 4)		
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, 54,621,701 and 51,551,937 issued and outstanding, respectively	546	516
Additional paid-in capital	669,717	525,763
Treasury stock, at cost, of none and 4,753 shares, respectively		(101)
Retained earnings	706,694	789,698
Accumulated other comprehensive loss	(1,038)	(1,748)
Total EAC stockholders equity	1,375,919	1,314,128
Noncontrolling interest	254,914	169,120
Total equity	1,630,833	1,483,248
Total liabilities and equity	$ 3,663,961	$ 3,633,195

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

ENCORE ACQUISITION COMPANY

CONSOLIDATED STATEMENTS OF OPERATIONS

	Year Ended December 31,		
	2009	2008	2007
	(In thousands, except per share amounts)		
Revenues:			
Oil	$ 549,391	$ 897,443	$ 562,817
Natural gas	131,185	227,479	150,107
Marketing	4,840	10,496	42,021
Total revenues	685,416	1,135,418	754,945
Expenses:			
Production:			
Lease operating	165,062	175,115	143,426
Production, ad valorem, and severance taxes	69,539	110,644	74,585
Depletion, depreciation, and amortization	290,776	228,252	183,980
Impairment of long-lived assets	9,979	59,526	
Exploration	52,488	39,207	27,726
General and administrative	54,024	48,421	39,124
Marketing	3,994	9,570	40,549
Derivative fair value loss (gain)	59,597	(346,236)	112,483
Provision for doubtful accounts	7,686	1,984	5,816
Other operating	25,761	12,975	17,066
Total expenses	738,906	339,458	644,755
Operating income (loss)	(53,490)	795,960	110,190
Other income (expenses):			
Interest	(79,017)	(73,173)	(88,704)
Other	2,447	3,898	2,667
Total other expenses	(76,570)	(69,275)	(86,037)
Income (loss) before income taxes	(130,060)	726,685	24,153
Income tax benefit (provision)	32,173	(241,621)	(14,476)
Consolidated net income (loss)	(97,887)	485,064	9,677
Less: net loss (income) attributable to noncontrolling interest	16,752	(54,252)	7,478
Net income (loss) attributable to EAC stockholders	$ (81,135)	$ 430,812	$ 17,155
Net income (loss) per common share:			

Basic	$ (1.54)	$ 8.10	$ 0.32
Diluted	$ (1.54)	$ 8.01	$ 0.31
Weighted average common shares outstanding:			
Basic	52,634	52,270	53,170
Diluted	52,634	52,866	53,629

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

Table of Contents

ENCORE ACQUISITION COMPANY

CONSOLIDATED STATEMENTS OF EQUITY AND COMPREHENSIVE INCOME (LOSS)

	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	Total EAC Stockholders Equity	Noncontrolling Interest	Tot Equ
						(In thousands)				
ce at ber 31,	53,047	$ 531	$ 457,201	(18)	$ (457)	$ 394,917	$ (35,327)	$ 816,865	$	$ 81
se of ptions sting of ed stock	313	3	1,587					1,590		
se of y stock				(39)	(1,136)			(1,136)		(
lation of y stock	(39)		(338)	39	1,003	(665)				
sh based nsation			14,632					14,632	2,627	1
ash utions to trolling t									(538)	
ash utions to s of ement ve units						(30)		(30)		
oceeds NP e of on units			(12,088)					(12,088)	205,549	19
ment to gain on suance mon			77,626					77,626	(77,626)	
nents of ehensive :										

idated ome						17,155		17,155	(7,478)	9
zation rred osses, ax of 7							33,541	33,541		3
ehensive :								50,696	(7,478)	4
e at ber 31,	53,321	534	538,620	(18)	(590)	411,377	(1,786)	948,155	122,534	1,07
se of ptions sting of ed stock	300	2	2,620					2,622		2
hase and ent of on stock	(2,018)	(20)	(19,279)			(47,871)		(67,170)		(6
se of y stock				(33)	(1,055)			(1,055)		(
lation of y stock	(46)		(465)	46	1,544	(1,079)				
sh based nsation			14,505					14,505	1,697	1
ash utions to trolling t									(24,004)	(2
ash utions to s of ement ve units						(3,541)		(3,541)		(
oceeds NP e of on units									5,748	5
ment to gain on suance mon			3,458					3,458	(3,458)	
mic nity nent to			(13,920)					(13,920)	13,920	

sion of ement ve units			224					224		
nents of ehensive :										
idated ome						430,812		430,812	54,252	48
e in d hedge interest aps, net f $957							(1,748)	(1,748)	(1,569)	(
zation rred loss modity ive ts, net f $1,071							1,786	1,786		
ehensive								430,850	52,683	48
e at ber 31,	51,557	516	525,763	(5)	(101)	789,698	(1,748)	1,314,128	169,120	1,48
se of ptions sting of ed stock	431	3	29					32		
oceeds suance C on stock	2,750	27	100,581					100,608		10
se of y stock				(111)	(2,961)			(2,961)		(
lation of y stock	(116)		(1,193)	116	3,062	(1,869)				
sh based nsation			14,843					14,843	172	1
ash utions to trolling t									(37,723)	(3
oceeds suance on units									169,806	16

ment to gain on suance mon			29,577				29,577	(29,577)	
mic nity nent to sion of ement ve units			(78)				(78)	78	
			195				195		
onents of ehensive									
idated s					(81,135)		(81,135)	(16,752)	(9
e in d hedge interest aps, net of $344						710	710	(210)	
ehensive							(80,425)	(16,962)	(9
ce at ber 31,	54,622	$ 546	$ 669,717	$	$ 706,694	$ (1,038)	$ 1,375,919	$ 254,914	$ 1,63

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

Table of Contents

ENCORE ACQUISITION COMPANY

CONSOLIDATED STATEMENTS OF CASH FLOWS

	Year Ended December 31, 2009	2008	2007
	(In thousands)		
Cash flows from operating activities:			
Consolidated net income (loss)	$ (97,887)	$ 485,064	$ 9,677
Adjustments to reconcile net income (loss) to net cash provided by operating activities:			
Depletion, depreciation, and amortization	290,776	228,252	183,980
Impairment of long-lived assets	9,979	59,526	
Non-cash exploration expense	50,693	34,874	25,487
Deferred taxes	(51,280)	232,614	12,588
Non-cash equity-based compensation expense	12,731	14,115	15,997
Non-cash derivative loss (gain)	181,409	(299,914)	130,910
Inventory valuation	6,473		
Loss (gain) on disposition of assets	(2,145)	(3,623)	7,409
Provision for doubtful accounts	7,686	1,984	5,816
Other	10,118	6,479	10,182
Changes in operating assets and liabilities, net of effects from acquisitions:			
Accounts receivable	25,022	(8,488)	(48,647)
Current derivatives	256,261	(13,681)	(17,430)
Other current assets	19,621	(35,495)	3,108
Long-term derivatives		(8,601)	(35,750)
Other assets	(396)	(2,174)	(1,214)
Accounts payable	2,283	(11,468)	4,461
Other current liabilities	25,907	(14,351)	14,788
Other noncurrent liabilities	(1,574)	(1,876)	(1,655)
Net cash provided by operating activities	745,677	663,237	319,707
Cash flows from investing activities:			
Proceeds from disposition of assets	6,032	4,235	287,928
Purchases of other property and equipment	(7,627)	(4,208)	(3,519)
Acquisition of oil and natural gas properties	(432,957)	(142,559)	(848,545)
Development of oil and natural gas properties	(342,298)	(560,997)	(335,897)
Net collections from (advances to) working interest partners	7,420	(24,817)	(29,523)
Net cash used in investing activities	(769,430)	(728,346)	(929,556)
Cash flows from financing activities:			
Repurchase and retirement of common stock		(67,170)	
	(2,929)	1,567	454

Exercise of stock options and vesting of restricted stock, net of treasury stock purchases			
Proceeds from long-term debt, net of issuance costs	632,166	1,370,339	1,479,259
Payments on long-term debt	(750,000)	(1,172,500)	(1,034,428)
Proceeds from issuance of EAC common stock, net of offering costs	100,608		
Proceeds from issuance of ENP common units, net of offering costs	170,088		193,461
ENP cash distributions to noncontrolling interest and holders of management incentive units	(37,723)	(27,545)	(568)
Payments of deferred commodity derivative contract premiums	(71,376)	(39,184)	(26,195)
Change in cash overdrafts	(5,162)	(63)	(1,193)
Net cash provided by financing activities	35,672	65,444	610,790
Increase in cash and cash equivalents	11,919	335	941
Cash and cash equivalents, beginning of period	2,039	1,704	763
Cash and cash equivalents, end of period	$ 13,958	$ 2,039	$ 1,704

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

ENCORE ACQUISITION COMPANY

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

Note 1. Description of Business

Encore Acquisition Company (together with its subsidiaries, EAC), a Delaware corporation, is engaged in the acquisition and development of oil and natural gas reserves from onshore fields in the United States. Since 1998, EAC has acquired producing properties with proven reserves and leasehold acreage and grown the production and proven reserves by drilling, exploring, reengineering, or expanding existing waterflood projects, and applying tertiary recovery techniques. EAC s properties and oil and natural gas reserves are located in four core areas:

the Cedar Creek Anticline (CCA) in the Williston Basin 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.

Merger with Denbury

On October 31, 2009, EAC entered into an Agreement and Plan of Merger (the Merger Agreement) with Denbury Resources Inc. (Denbury) pursuant to which EAC has agreed to merge with and into Denbury, with Denbury as the surviving entity (the Merger). The Merger Agreement, which was unanimously approved by EAC s Board of Directors (the Board) and by Denbury s Board of Directors, provides for Denbury s acquisition of all of the issued and outstanding shares of EAC common stock, par value $.01 per share, in a transaction valued at approximately $4.5 billion, including the assumption of debt and the value of EAC s interest in Encore Energy Partners LP (together with its subsidiaries, ENP), a publicly traded Delaware limited partnership. Completion of the Merger is conditioned upon, among other things, approval by the stockholders of both EAC and Denbury.

Note 2. Summary of Significant Accounting Policies

Principles of Consolidation

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.

Noncontrolling Interest

In February 2007, EAC formed ENP to acquire, exploit, and develop oil and natural gas properties and to acquire, own, and operate related assets. In September 2007, ENP completed its initial public offering (IPO). As of December 31, 2009 and 2008, EAC owned approximately 46 percent and 63 percent, respectively, of ENP s common units. EAC also owns 100 percent of Encore Energy Partners GP LLC (GP LLC), a Delaware limited liability company and indirect wholly owned non-guarantor subsidiary of EAC, which is ENP s general partner. Considering the presumption of control of GP LLC in accordance with Financial Accounting Standards Board (FASB) Accounting

Standards Codification (ASC) 810-20 (formerly 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 fully consolidated with those of EAC.

As presented in the accompanying Consolidated Balance Sheets, Noncontrolling interest as of December 31, 2009 and 2008 of $254.9 million and $169.1 million, respectively, represents third-party ownership interests in ENP. As presented in the accompanying Consolidated Statements of Operations, Net

ENCORE ACQUISITION COMPANY

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

loss attributable to noncontrolling interest for 2009 and 2007 of $16.8 million and $7.5 million, respectively, and Net income attributable to noncontrolling interest for 2008 of $54.3 million, represents ENP s results of operations attributable to third-party owners.

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

	Year Ended December 31, 2009	2008	2007
		(In thousands)	
Net income (loss) attributable to EAC stockholders	$ (81,135)	$ 430,812	$ 17,155
Transfer from (to) noncontrolling interest:			
Increase in EAC s paid-in capital for ENP s issuance of 10,148,400 common units in public offering			77,626
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	
Increase in EAC s paid-in capital for ENP s issuance of 2,760,000 common units in public offering	9,312		
Increase in EAC s paid-in capital for ENP s issuance of 9,430,000 common units in public offering	20,265		
Net transfer from noncontrolling interest	29,577	3,458	77,626
Change from net income (loss) attributable to EAC stockholders and transfers from (to) noncontrolling interest	$ (51,558)	$ 434,270	$ 94,781

Use of Estimates

Preparing financial statements in conformity with accounting principles generally accepted in the United States (GAAP) requires management to make certain estimations and assumptions that affect the reported amounts of assets, liabilities, revenues, and expenses, and the disclosure of contingent assets and liabilities in the consolidated financial statements. Actual results could differ materially from those estimates.

Estimates made in preparing these consolidated financial statements include, among other things, estimates of the proved oil and natural gas reserve volumes used in calculating depletion, depreciation, and amortization (DD&A) expense; the estimated future cash flows and fair value of properties used in determining the need for any impairment write-down; operating costs accrued; volumes and prices for revenues accrued; estimates of the fair value of equity-based compensation awards; and the timing and amount of future abandonment costs used in calculating asset retirement obligations. Changes in the assumptions used could have a significant impact on reported results in future periods.

Cash and Cash Equivalents

Cash and cash equivalents include cash in banks, money market accounts, and all highly liquid investments with an original maturity of three months or less. On a bank-by-bank basis and considering legal right of offset, cash accounts that are overdrawn are reclassified to current liabilities and any change in cash overdrafts is shown as Change in cash overdrafts in the Financing activities section of EAC s Consolidated Statements of Cash Flows.

ENCORE ACQUISITION COMPANY

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

	Year Ended December 31,		
	2009	2008	2007
	(In thousands)		
Cash paid during the period for:			
Interest	$ 66,952	$ 67,519	$ 82,649
Income taxes	9,075	33,110	260
Non-cash investing and financing activities:			
Deferred premiums on commodity derivative contracts	50,972	53,387	20,341
ENP s issuance of common units in connection with acquisition of net profits interest in certain Crockett County properties		5,748	

Accounts Receivable

Trade accounts receivable, which are primarily from oil and natural gas sales, are recorded at the invoiced amount and do not bear interest with the exception of balances due from ExxonMobil Corporation (ExxonMobil) in connection with EAC s joint development agreement. EAC routinely reviews outstanding accounts receivable balances and assesses the financial strength of its customers and records a reserve for amounts not expected to be fully recovered. Actual balances are not applied against the reserve until substantially all collection efforts have been exhausted.

During 2009 and 2008, EAC recorded an allowance for doubtful accounts of approximately $7.7 million and $2.0 million, respectively, primarily related to balances due from ExxonMobil in connection with EAC s joint development agreement, which are included in Provision for doubtful accounts in the accompanying Consolidated Statements of Operations. The following table summarizes the changes in EAC s allowance for doubtful accounts for the periods indicated:

	Year Ended December 31,	
	2009	2008
	(In thousands)	
Allowance for doubtful accounts at January 1	$ 8,024	$ 6,045
Bad debt expense	7,686	1,984
Write off	(1,631)	(5)
Allowance for doubtful accounts at December 31	$ 14,079	$ 8,024

As of December 31, 2009, $0.4 million of EAC s allowance for doubtful accounts was current and $13.6 million was long-term.

84

ENCORE ACQUISITION COMPANY

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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:

	December 31, 2009	December 31, 2008
	(In thousands)	
Materials and supplies	$ 17,931	$ 15,933
Oil in pipelines	8,743	8,865
Total inventory	$ 26,674	$ 24,798

During 2009, EAC recorded a lower of cost or market adjustment of approximately $6.5 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.

Properties and Equipment

Oil and Natural Gas Properties. EAC uses the successful efforts method of accounting for its oil and natural gas properties under ASC 932 (formerly Statement of Financial Accounting Standards (SFAS) No. 19, *Financial Accounting and Reporting by Oil and Gas Producing Companies*). Under this method, all costs associated with productive and nonproductive development wells are capitalized. Exploration expenses, including geological and geophysical expenses and delay rentals, are charged to expense as incurred. Costs associated with drilling exploratory wells are initially capitalized pending determination of whether the well is economically productive or nonproductive.

If an exploratory well does not find reserves or does not find reserves in a sufficient quantity as to make them economically producible, the previously capitalized costs are expensed in EAC s Consolidated Statements of Operations and shown as an adjustment to net income (loss) in the Operating activities section of EAC s Consolidated Statements of Cash Flows in the period in which the determination was made. If an exploratory well finds reserves but they cannot be classified as proved, EAC continues to capitalize the associated cost as long as the well has found a sufficient quantity of reserves to justify its completion as a producing well and EAC is making sufficient progress in assessing the reserves and the operating viability of the project. If subsequently it is determined that these conditions do not continue to exist, all previously capitalized costs associated with the exploratory well are expensed and shown as an adjustment to net income (loss) in the Operating activities section of EAC s Consolidated Statements of Cash Flows in the period in which the determination is made. Re-drilling or directional drilling in a previously abandoned well is classified as development or exploratory based on whether it is in a proved or unproved reservoir. Costs for repairs and maintenance to sustain or increase production from the existing producing reservoir are charged to expense as incurred. Costs to recomplete a well in a different unproved reservoir are capitalized pending determination that economic reserves have been added. If the recompletion is unsuccessful, the costs are charged to expense. All capitalized costs associated with both development and exploratory wells are shown as Development of oil and natural gas properties in the Investing activities section of EAC s Consolidated Statements of Cash Flows.

Significant tangible equipment added or replaced that extends the useful or productive life of the property is capitalized. Costs to construct facilities or increase the productive capacity from existing reservoirs are capitalized. Internal costs directly associated with the development of proved properties are capitalized as a cost of the property and are classified accordingly in EAC s consolidated financial statements. Capitalized costs are amortized on a unit-of-production basis over the remaining life of proved developed reserves or total

ENCORE ACQUISITION COMPANY

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

proved reserves, as applicable. Natural gas volumes are converted to barrels of oil equivalent (BOE) at the rate of six thousand cubic feet (Mcf) of natural gas to one barrel (Bbl) of oil.

The costs of retired, sold, or abandoned properties that constitute part of an amortization base are charged or credited, net of proceeds received, to accumulated DD&A.

Miller and Lents, Ltd., EAC s independent reserve engineer, estimates EAC s reserves annually on December 31. This results in a new DD&A rate which EAC uses for the preceding fourth quarter after adjusting for fourth quarter production. EAC internally estimates reserve additions and reclassifications of reserves from proved undeveloped to proved developed at the end of the first, second, and third quarters for use in determining a DD&A rate for the respective quarter.

In accordance with ASC 360-10, 205, 840, 958, and 855-10-60-1 (formerly SFAS No. 144, *Accounting for the Impairment or Disposal of Long-Lived Assets*), EAC assesses the need for an impairment of long-lived assets to be held and used, including proved oil and natural gas properties, whenever events and circumstances indicate that the carrying value of the asset may not be recoverable. If impairment is indicated based on a comparison of the asset s carrying value to its undiscounted expected future net cash flows, then an impairment charge is recognized to the extent the asset s carrying value exceeds its fair value. Expected future net cash flows are based on existing proved reserves (and appropriately risk-adjusted probable reserves), forecasted production information, and management s outlook of future commodity prices. Any impairment charge incurred is expensed and reduces the net basis in the asset. Management aggregates proved property for impairment testing the same way as for calculating DD&A. The price assumptions used to calculate undiscounted cash flows is based on judgment. EAC uses prices consistent with the prices it believes a market participant would use in bidding on acquisitions and/or assessing capital projects. These price assumptions are critical to the impairment analysis as lower prices could trigger impairment.

Unproved properties, the majority of which relate to the acquisition of leasehold interests, are assessed for impairment on a property-by-property basis for individually significant balances and on an aggregate basis for individually insignificant balances. If the assessment indicates impairment, a loss is recognized by providing a valuation allowance at the level at which impairment was assessed. The impairment assessment is affected by economic factors such as the results of exploration activities, commodity price outlooks, remaining lease terms, and potential shifts in business strategy employed by management. In the case of individually insignificant balances, the amount of the impairment loss recognized is determined by amortizing the portion of these properties costs which EAC believes will not be transferred to proved properties over the remaining life of the lease.

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:

	December 31, 2009	December 31, 2008
	(In thousands)	
Proved leasehold costs	$ 1,782,042	$ 1,421,859
Wells and related equipment Completed	2,408,662	1,943,275

Wells and related equipment	In process	13,918	173,325
Total proved properties		$ 4,204,622	$ 3,538,459

Other Property and Equipment. Other property and equipment is carried at cost. Depreciation is expensed on a straight-line basis over estimated useful lives, which range from three to seven years. Leasehold improvements are capitalized and depreciated over the remaining term of the lease, which is through 2013 for EAC s corporate headquarters. Gains or losses from the disposal of other property and equipment are

86

ENCORE ACQUISITION COMPANY

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

recognized in the period realized and included in Other operating expense in the accompanying Consolidated Statements of Operations.

Goodwill and Other Intangible Assets

EAC accounts for goodwill and other intangible assets under the provisions of ASC 350, 730-10-60-3, 323-10-35-13, 205-20-60-4, and 280-10-60-2 (formerly SFAS No. 142, *Goodwill and Other Intangible Assets*). Goodwill represents the excess of the purchase price over the estimated fair value of the net assets acquired in business combinations. Goodwill is tested for impairment annually on December 31 or whenever indicators of impairment exist. The goodwill test is performed at the reporting unit level. EAC has determined that it has two reporting units: EAC Standalone and ENP. As of December 31, 2009, ENP has been allocated $9.3 million of goodwill and the remainder has been allocated to the EAC Standalone segment. If indicators of impairment are determined to exist, an impairment charge is recognized for the amount by which the carrying value of goodwill exceeds its implied fair value.

EAC utilizes both a market capitalization and an income approach to determine the fair value of its reporting units. The primary component of the income approach is the estimated discounted future net cash flows expected to be recovered from the reporting unit s oil and natural gas properties. EAC s analysis concluded that there was no impairment of goodwill as of December 31, 2009. Significant decreases in the prices of oil and natural gas or significant negative reserve adjustments from the December 31, 2009 assessment could change EAC s estimates of the fair value of its reporting units and could result in an impairment charge.

Intangible assets with definite useful lives are amortized over their estimated useful lives. In accordance with ASC 410-20, 450-20, 835-20, 360-10-35, 840-10, and 980-410, EAC evaluates the recoverability of intangible assets with definite useful lives whenever events or changes in circumstances indicate that the carrying value of the asset may not be fully recoverable. An impairment loss exists when the estimated undiscounted cash flows expected to result from the use of the asset and its eventual disposition are less than its carrying amount.

ENP is a party to a contract allowing it to purchase a certain amount of natural gas at a below market price for use as field fuel. As of December 31, 2009, the gross carrying value of this contact was $4.2 million and accumulated amortization was $0.9 million. During each of 2009, 2008, and 2007, ENP recorded approximately $0.3 million of amortization expense related to this contract. The net carrying value is included in Other noncurrent assets on the accompanying Consolidated Balance Sheets and is being amortized on a straight-line basis through November 2020. ENP expects to recognize $0.3 million of amortization expense during each of the next five years related to this contract.

In July 2009, EAC acquired a private company for $24 million in cash, which procured a carbon dioxide (CO_2) supply intended to be used for a tertiary oil recovery project in EAC s Bell Creek Field. The CO_2 purchasable is not transportable as capture and compression facilities and a related pipeline need to be built. Until the CO_2 can be transported to the field and the capture, compression, and injection of the CO_2 proves economic, the contract has an unknown useful life. This contract is included in Other noncurrent assets on the accompanying Consolidated Balance Sheet.

Asset Retirement Obligations

In accordance with ASC 410-20, 450-20, 835-20, 360-10-35, 840-10, and 980-410 (formerly SFAS No. 143, *Accounting for Asset Retirement Obligations*), EAC recognizes the fair value of a liability for an asset retirement obligation in the period in which the liability is incurred. For oil and natural gas properties, this is the period in which the property is acquired or a new well is drilled. An amount equal to and offsetting the liability is capitalized as part of the carrying amount of EAC s oil and natural gas properties.

Table of Contents

ENCORE ACQUISITION COMPANY

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

The liability is recorded at its risk adjusted discounted fair value and then accreted each period until it is settled or the asset is sold, at which time the liability is reversed. Estimates are based on historical experience in plugging and abandoning wells and estimated remaining field life based on reserve estimates. Please read Note 5. Asset Retirement Obligations for additional information.

Equity-Based Compensation

EAC accounts for equity-based compensation according to the provisions of ASC 718, 505-50, and 260-10-60-1A formerly SFAS No. 123 (revised 2004), *Share-Based Payment*), which requires the recognition of compensation expense for equity-based awards over the requisite service period in an amount equal to the grant date fair value of the awards. EAC utilizes a standard option pricing model (i.e., Black-Scholes) to measure the fair value of employee stock options under ASC 718, 505-50, and 260-10-60-1A. Please read Note 11. Employee Benefit Plans for additional discussion of EAC s employee benefit plans.

ASC 718, 505-50, and 260-10-60-1A also requires that the benefits associated with the tax deductions in excess of recognized compensation cost be reported as a financing cash flow. This requirement reduces net operating cash flows and increases net financing cash flows. EAC recognizes compensation costs related to awards with graded vesting on a straight-line basis over the requisite service period for each separately vesting portion of the award as if the award was, in-substance, multiple awards. Compensation expense associated with awards to employees who are eligible for retirement is fully expensed on the date of grant.

Segment Reporting

EAC operates in only one industry: the oil and natural gas exploration and production industry in the United States. However, EAC is organizationally structured along two reportable segments: EAC Standalone and ENP. EAC s segments are components of its business for which separate financial information related to operating and development costs are available and regularly evaluated by the chief operating decision maker in deciding how to allocate capital resources to projects and in assessing performance. Please read Note 16. Segment Information for additional discussion.

Major Customers/Concentration of Credit Risk

The following purchasers accounted for 10 percent or greater of the sales of production for the period indicated:

	Percentage of Total Sales of Production for the Year Ended December 31,		
	2009	**2008**	**2007**
Consolidated EAC			
Eight-Eight Oil	18%	14%	14%
Tesoro Refining & Marketing Co	(a)	12%	(a)
ENP			

Marathon Oil Corporation	42%	19%	24%
ConocoPhillips	(a)	17%	10%
Tesoro Refining & Marketing Co	(a)	15%	17%
EAC Standalone			
Eight-Eight Oil	22%	23%	29%
Tesoro Refining & Marketing Co	(a)	13%	(a)

(a) Less than 10 percent for the period indicated.

ENCORE ACQUISITION COMPANY

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Income Taxes

Deferred tax assets and liabilities are recognized for future tax consequences attributable to differences between financial statement carrying amounts of existing assets and liabilities and their respective tax bases. Valuation allowances are established when necessary to reduce net deferred tax assets to amounts expected to be realized. Deferred tax assets and liabilities are measured using enacted tax rates expected to apply to taxable income in the years in which those temporary differences are expected to be recovered or settled.

EAC accounts for uncertainty in income taxes in accordance with ASC 740, 805-740, and 835-10 (formerly FASB Interpretation No. 48, *Accounting for Uncertainty in Income Taxes an Interpretation of FASB Statement No. 109*). ASC 740, 805-740, and 835-10 prescribes a recognition threshold and measurement attribute for the financial statement recognition and measurement of a tax position taken or expected to be taken in a tax return. EAC and its subsidiaries file income tax returns in the U.S. federal jurisdiction and various state jurisdictions. Subject to statutory exceptions that allow for a possible extension of the assessment period, EAC is no longer subject to U.S. federal, state, and local income tax examinations for years prior to 2004.

EAC performs a periodic evaluation of tax positions to review the appropriate recognition threshold for each tax position recognized in EAC s financial statements, including, but not limited to:

- a review of documentation of tax positions taken on previous returns including an assessment of whether EAC followed industry practice or the applicable requirements under the tax code;
- a review of open tax returns (on a jurisdiction by jurisdiction basis) as well as supporting documentation used to support those tax returns;
- a review of the results of past tax examinations;
- a review of whether tax returns have been filed in all appropriate jurisdictions;
- a review of existing permanent and temporary differences; and
- consideration of any tax planning strategies that may have been used to support realization of deferred tax assets.

As of December 31, 2009 and 2008, all of EAC s tax positions met the more-likely-than-not threshold prescribed by ASC 740, 805-740, and 835-10. 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. For 2009, 2008, and 2007, EAC recorded only a nominal amount of interest and penalties on certain tax positions.

Oil and Natural Gas Revenue Recognition

Oil and natural gas revenues are recognized as oil and natural gas is produced and sold, net of royalties and net profits interests. Royalties, net profits interests, and severance taxes are incurred based upon the actual price received from the sales. To the extent actual quantities and values of oil and natural gas are unavailable for a given reporting period because of timing or information not received from third parties, the expected sales volumes and prices for those properties are estimated and recorded as Accounts receivable, net in the accompanying Consolidated Balance Sheets. Natural gas revenues are reduced by any processing and other fees incurred except for transportation costs paid to third parties, which are recorded in Other operating expense in the accompanying Consolidated Statements of Operations. Natural gas revenues are recorded using the sales method of accounting whereby revenue is recognized based on actual sales of natural gas rather than EAC s proportionate share of natural gas production. If EAC s overproduced imbalance position (i.e., EAC has cumulatively been over-allocated production) is greater than EAC s share of remaining reserves, a liability is recorded for the excess at period-end prices unless a different price is specified in the contract in which case

ENCORE ACQUISITION COMPANY

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

that price is used. Revenue is not recognized for the production in tanks, oil marketed on behalf of joint owners in EAC s properties, or oil in pipelines that has not been delivered to the purchaser.

EAC s net oil inventories in pipelines were 117,363 Bbls and 173,119 Bbls at December 31, 2009 and 2008, respectively. Natural gas imbalances at December 31, 2009 were 456,912 million British thermal units (MMBtu) over-delivered to EAC, the value of which was approximately $2.3 million. Natural gas imbalances at December 31, 2008, were 28,717 MMBtu under-delivered to EAC the value of which was approximately $0.1 million.

Marketing Revenues and Expenses

In March 2007, ENP acquired a crude oil pipeline and a natural gas pipeline as part of the Elk Basin acquisition. 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. In addition, pipeline tariffs are collected for transportation through the crude oil pipeline.

Marketing revenues include the sales of oil and natural gas purchased from third parties as well as pipeline tariffs charged for transportation volumes through EAC s pipelines. Marketing revenues derived from sales of oil and natural gas purchased from third parties are recognized when persuasive evidence of a sales arrangement exists, delivery has occurred, the sales price is fixed or determinable, and collectibility is reasonably assured. As EAC takes title to the oil and natural gas and has risks and rewards of ownership, these transactions are presented gross in the accompanying Consolidated Statements of Operations, unless they meet the criteria for netting as outlined in ASC 845-10 (formerly EITF Issue No. 04-13, *Accounting for Purchases and Sales of Inventory with the Same Counterparty*).

Shipping Costs

Shipping costs in the form of pipeline fees and trucking costs paid to third parties are incurred to transport oil and natural gas production from certain properties to a different market location for ultimate sale. These costs are included in Other operating expense and Marketing expense, as applicable, in the accompanying Consolidated Statements of Operations.

Derivatives

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 ASC 815 (formerly SFAS No. 133, *Accounting for Derivative Instruments and Hedging Activities*), 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, the effective portion of changes in fair value can be recognized in accumulated other comprehensive income or 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.

EAC has elected to designate its outstanding 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

ENCORE ACQUISITION COMPANY

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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 and included in Derivative fair value loss (gain) 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 and included in Derivative fair value loss (gain) in the accompanying Consolidated Statements of Operations.

Earnings Per Share

For purposes of calculating earnings per share, EAC allocates net income (loss) to its shareholders and participating securities each quarter under the provisions of ASC 260-10 (formerly EITF Issue No. 03-6, *Participating Securities and the Two-Class Method under FASB Statement No. 128*). Under the two-class method of calculating earnings per share as prescribed by ASC 260-10, earnings are allocated to participating securities as if all the earnings for the period had been distributed. A participating security is any security that may participate in distributions with common shares. For purposes of calculating earnings per share, unvested restricted stock awards are considered participating securities. Net income (loss) per common share is calculated by dividing the shareholders interest in net income (loss), after deducting the interests of participating securities, by the weighted average common shares outstanding. Please read New Accounting Pronouncements below and Note 10. Earnings Per Share for additional discussion.

Comprehensive Income (Loss)

EAC has elected to show comprehensive income (loss) as part of its Consolidated Statements of Equity and Comprehensive Income (Loss) rather than in its Consolidated Statements of Operations or as a separate statement.

FASB Launches Accounting Standards Codification

In June 2009, the FASB issued ASC 105-10 (formerly SFAS No. 168, *The FASB Accounting Standards Codification and the Hierarchy of Generally Accepted Accounting Principles*). ASC 105-10 establishes the 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. ASC 105-10 was prospectively effective for financial statements issued for fiscal years ending on or after September 15, 2009, and interim periods within those fiscal years. The adoption of ASC 105-10 on July 1, 2009 did not impact EAC s results of operations or financial condition.

Following the Codification, the FASB does not issue new standards in the form of Statements, FASB Staff Positions (FSP), or EITF Abstracts. Instead, it issues Accounting Standards Updates (ASU), which update the Codification, provide background information about the guidance, and provide the basis for conclusions on the changes to the Codification.

The Codification did not change GAAP; however, it did change the way GAAP is organized and presented. As a result, these changes impact how companies, including EAC, reference GAAP in their financial statements and in their significant accounting policies.

New Accounting Pronouncements

ASC 820-10 (formerly FSP No. FAS 157-2, Effective Date of FASB Statement No. 157)

In February 2008, the FASB issued ASC 820-10, which delayed the effective date of ASC 820-10 for one year for nonfinancial assets and liabilities, except those that are recognized or disclosed at fair value in the

ENCORE ACQUISITION COMPANY

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

financial statements on a recurring basis (at least annually). ASC 820-10 was prospectively effective for financial statements issued for fiscal years beginning after November 15, 2008, and interim periods within those fiscal years. EAC elected a partial deferral of ASC 820-10 for all instruments within the scope of ASC 820-10, including, but not limited to, its asset retirement obligations and indefinite lived assets. The adoption of ASC 820-10 on January 1, 2009 as it relates to nonfinancial assets and liabilities did not have a material impact on EAC s results of operations or financial condition. Please read Note 12. Fair Value Measurements for additional discussion.

ASC 805 (formerly SFAS No. 141 (revised 2007), Business Combinations)

In December 2007, the FASB issued ASC 805, which 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 ASC 805-20 (formerly FSP No. FAS 141(R)-1, *Accounting for Assets Acquired and Liabilities Assumed in a Business Combination That Arises from Contingencies*), which amends and clarifies ASC 805 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. ASC 805 and ASC 805-20 were prospectively effective for business combinations consummated in fiscal years beginning on or after December 15, 2008. The application of ASC 805 and ASC 805-20 to the acquisition of certain oil and natural gas properties and related assets in the Mid-Continent and East Texas resulted in the expensing of approximately $1.5 million of transaction costs. Please read Note 3. Acquisitions and Dispositions for additional discussion.

ASC 810-10-65-1 (formerly SFAS No. 160, Noncontrolling Interests in Consolidated Financial Statements an amendment to ARB No. 51)

In December 2007, the FASB issued ASC 810-10-65-1, which establishes accounting and reporting standards for the noncontrolling interest in a subsidiary and for the deconsolidation of a subsidiary. ASC 810-10-65-1 was prospectively effective for financial statements issued for fiscal years beginning on or after December 15, 2008, except for the presentation and disclosure requirements which were retrospectively effective. ASC 810-10-65-1 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, ASC 810-10-65-1 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 or losses on a subsidiaries issuance of equity to be accounted for as capital transactions. The adoption of ASC 810-10-65-1 on January 1, 2009 did not have a material impact on EAC s results of operations or financial condition. The retrospective application of ASC 810-10-65-1 resulted in the reclassification of approximately $169.1 million from Minority interest in consolidated partnership to Noncontrolling interest at December 31, 2008 on the accompanying Consolidated Balance Sheets.

ASC 815-10 (formerly SFAS No. 161, Disclosures about Derivative Instruments and Hedging Activities an amendment of FASB Statement No. 133)

In March 2008, the FASB issued ASC 815-10, which requires enhanced disclosures: including (1) how and why an entity uses derivative instruments; (2) how derivative instruments and related hedged items are accounted for under ASC 815; and (3) how derivative instruments and related hedged items affect an entity s financial position, financial performance, and cash flows. ASC 815-10 was prospectively effective for financial

ENCORE ACQUISITION COMPANY

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

statements issued for fiscal years beginning on or after November 15, 2008, and interim periods within those fiscal years. The adoption of ASC 815-10 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 12. Fair Value Measurements for additional discussion.

ASC 260-10 (formerly FSP No. EITF 03-6-1, Determining Whether Instruments Granted in Share-Based Payment Transactions Are Participating Securities)

In June 2008, the FASB issued ASC 260-10, which addresses whether instruments granted in share-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 under the two-class method. ASC 260-10 was retroactively effective for financial statements issued for fiscal years beginning after December 15, 2008, and interim periods within those years. In the accompanying Consolidated Financial Statements, periods prior to the adoption of ASC 260-10 have been restated to calculate earnings per share in accordance with this pronouncement. The retrospective application of ASC 260-10 reduced EAC s basic earnings per share by $0.14 for the year ended December 31, 2008 and reduced EAC s diluted earnings per share by $0.06 and $0.01 for the years ended December 31, 2008 and 2007, respectively. The adoption of ASC 260-10 did not have an impact on EAC s basic earnings per share for the year ended December 31, 2007. Please read Note 10. Earnings Per Unit for additional discussion.

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

In December 2008, the United States Securities and Exchange Commission (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 was prospectively effective for financial statements issued for fiscal years ending on or after December 31, 2009.

ASC 855-10 (formerly SFAS No. 165, Subsequent Events)

In June 2009, the FASB issued ASC 855-10 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, ASC 855-10 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. ASC 855-10 was prospectively effective for financial statements issued for interim or annual periods ending after June 15, 2009. The adoption of ASC 855-10 on June 30, 2009 did not impact EAC s results of operations or financial condition.

ENCORE ACQUISITION COMPANY

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

ASU No. 2009-05, Fair Value Measurement and Disclosure: Measuring Liabilities at Fair Value (ASU 2009-05)

In August 2009, the FASB issued ASU 2009-05 to provide clarification on measuring liabilities at fair value when a quoted price in an active market is not available. In particular, ASU 2009-05 specifies that a valuation technique should be applied that used either the quote of the liability when traded as an asset, the quoted prices for similar liabilities or similar liabilities when traded as assets, or another valuation technique consistent with existing fair value measurement guidance. ASU 2009-05 was prospectively effective for financial statements issued for interim or annual periods ending after October 1, 2009. The adoption of ASU 2009-05 on December 31, 2009 did not impact EAC s results of operations or financial condition.

ASU No. 2010-03, Oil and Gas Reserve Estimation and Disclosure (ASU 2010-03)

In January 2010, the FASB issued ASU 2010-03 to align the oil and natural gas reserve estimation and disclosure requirements of Extractive Activities Oil and Gas (ASC 932) with the requirements in the SEC s final rule, *Modernization of the Oil and Gas Reporting*. ASU 2010-03 was prospectively effective for financial statements issued for annual periods ending on or after December 31, 2009.

ASU No. 2010-06, Improving Disclosures about Fair Value Measurements (ASU 2010-06)

In January 2010, the FASB issued ASU 2010-06 to require additional information to be disclosed principally in respect of level 3 fair value measurements and transfers to and from Level 1 and Level 2 measurements; in addition, enhanced disclosure is required concerning inputs and valuation techniques used to determine Level 2 and Level 3 fair value measurements. ASU 2010-06 was generally effective for interim and annual reporting periods beginning after December 15, 2009; however, the requirements to disclose separately purchases, sales, issuances, and settlements in the Level 3 reconciliation are effective for fiscal years beginning after December 15, 2010 (and for interim periods within such years) with early adoption allowed. The adoption of ASU 2010-06 on December 31, 2009 did not impact EAC s results of operations or financial condition.

Note 3. Acquisitions and Dispositions

Acquisitions

EXCO. In August 2009, EAC acquired certain oil and natural gas properties and related assets in the Mid-Continent and East Texas from EXCO Resources, Inc. (together with its affiliates, EXCO) for approximately $357.4 million in cash, substantially all of which are proved producing. The operations of these properties have been included with those of EAC from the date of acquisition forward. EAC financed the acquisitions through borrowings under its revolving credit facility and proceeds from the issuance of ENP common units to the public.

ENCORE ACQUISITION COMPANY

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

The allocation of the purchase price to the fair value of the assets acquired and liabilities assumed from EXCO were as follows (in thousands):

Proved properties, including wells and related equipment	$ 367,341
Accounts receivable	6,191
Other property and equipment	435
Total assets acquired	373,967
Current liabilities	4,791
Future abandonment cost	11,764
Total liabilities assumed	16,555
Fair value of net assets acquired	$ 357,412

Vinegarone. In May 2009, ENP acquired certain natural gas properties in the Vinegarone Field in Val Verde County, Texas (the Vinegarone Assets) from an independent energy company for approximately $27.5 million in cash, which was financed through proceeds from the issuance of ENP common units to the public. The results of operations of the Vinegarone Assets are included with those of EAC from the date of acquisition forward.

Anadarko. In April 2007, EAC acquired certain oil and natural gas properties and related assets in the Williston Basin of Montana and North Dakota from certain subsidiaries of Anadarko Petroleum Corporation (Anadarko) for approximately $392.1 million in cash. The operations of these properties have been included with those of EAC from the date of acquisition forward. EAC financed the acquisition through borrowings under its revolving credit facility.

In March 2007, EAC acquired certain oil and natural gas properties and related assets in the Big Horn Basin of Wyoming and Montana, which included oil and natural gas properties and related assets in or near the Elk Basin field in Park County, Wyoming and Carbon County, Montana and oil and natural gas properties and related assets in the Gooseberry field in Park County, Wyoming, from Anadarko for approximately $393.6 million in cash. Prior to closing, EAC assigned the rights and duties under the purchase and sale agreement relating to the Elk Basin assets to Encore Energy Partners Operating LLC (OLLC), a Delaware limited liability company and wholly owned subsidiary of ENP, and the rights and duties under the purchase and sale agreement relating to the Gooseberry assets to Encore Operating, L.P. (Encore Operating), a Texas limited partnership and indirect wholly owned guarantor subsidiary of EAC. The operations of these properties have been included with those of EAC from the date of acquisition forward. EAC financed the acquisitions of the Gooseberry assets and Williston Basin assets through borrowings under its revolving credit facility. ENP financed the acquisition of the Elk Basin assets through a $93.7 million contribution from EAC, $120 million of borrowings under a subordinated credit agreement with EAP Operating, LLC, a Delaware limited liability company and direct wholly owned guarantor subsidiary of EAC, and borrowings under OLLC s revolving credit facility.

Dispositions

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

Table of Contents

ENCORE ACQUISITION COMPANY

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Proceeds from the Mid-Continent asset disposition were used to reduce outstanding borrowings under EAC s revolving credit facility.

Pro Formas

The following unaudited pro forma condensed financial data was derived from the historical financial statements of EAC and from the accounting records of Anadarko and EXCO to give effect to the Anadarko asset acquisitions, the EXCO asset acquisitions, and the Mid-Continent asset disposition as if they had each occurred on January 1, 2007. The unaudited pro forma condensed financial information has been included for comparative purposes only and is not necessarily indicative of the results that might have occurred had the Anadarko asset acquisitions, the EXCO asset acquisitions, and the Mid-Continent asset disposition taken place on January 1, 2007 and is not intended to be a projection of future results.

	Year Ended December 31,		
	2009	2008	2007
	(In thousands, except per share amounts)		
Pro forma total revenues	$ 727,343	$ 1,294,513	$ 854,388
Pro forma net income (loss) attributable to EAC stockholders	$ (77,741)	$ 483,231	$ 48,004
Pro forma net income (loss) per common share:			
Basic	$ (1.48)	$ 9.14	$ 0.90
Diluted	$ (1.48)	$ 9.04	$ 0.89

Note 4. Commitments and Contingencies

Litigation

EAC is a party to ongoing legal proceedings in the ordinary course of business. Management does not believe the result of these proceedings will have a material adverse effect on EAC s business, financial position, results of operations, or liquidity.

Three shareholder lawsuits styled as class actions have been filed against EAC and the Board related to the Merger. The lawsuits are entitled:

(1) *Sanjay Israni, Individually and On Behalf of All Others Similarly Situated vs. Encore Acquisition Company et al.* (filed November 4, 2009 in the District Court of Tarrant County, Texas);

(2) *Teamsters Allied Benefit Funds, Individually and On Behalf of All Others Similarly Situated vs. Encore Acquisition Company et al.* (filed November 5, 2009 in the Court of Chancery in the State of Delaware); and

(3) *Thomas W. Scott, Jr., individually and on behalf of all others similarly situated v. Encore Acquisition Company et al.* (filed November 6, 2009 in the District Court of Tarrant County, Texas).

The *Teamsters* and *Scott* lawsuits also name Denbury as a defendant. The complaints generally allege that (1) EAC s directors breached their fiduciary duties in negotiating and approving the Merger and by administering a sale process that failed to maximize shareholder value and (2) EAC, and, in the case of the *Teamsters* and *Scott* complaints, Denbury aided and abetted EAC s directors in breaching their fiduciary duties. The *Teamsters* complaint also alleges that EAC s directors and executives stand to receive substantial financial benefits if the Merger is consummated on its current terms. The plaintiffs in these lawsuits seek, among other things, to enjoin the Merger and to rescind the Merger Agreement. EAC and Denbury have entered into a Memorandum of Understanding with the plaintiffs in these lawsuits agreeing in principle to the settlement of the lawsuits based upon inclusion in the joint proxy statement/prospectus of additional disclosures requested

ENCORE ACQUISITION COMPANY

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

by the plaintiffs, and agreeing that the parties to the lawsuits will use best efforts to enter into a definitive settlement agreement and seek court approval for the settlement which would be binding on all EAC shareholders who do not opt-out of the settlement.

Leases

EAC leases office space and equipment that have non-cancelable lease terms in excess of one year. The following table summarizes by year the remaining non-cancelable future payments under these operating leases as of December 31, 2009 (in thousands):

2010	$ 3,635
2011	3,597
2012	3,358
2013	2,607
2014	
Thereafter	
	$ 13,197

EAC s operating lease rental expense was approximately $4.9 million, $5.8 million, and $5.5 million in 2009, 2008, and 2007, respectively.

Note 5. 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 periods indicated:

	Year Ended December 31, 2009 (In thousands)	Year Ended December 31, 2008 (In thousands)
Future abandonment liability at January 1	$ 49,569	$ 28,079
Wells drilled	300	498
Acquisition of properties	3,666	111
Disposition of properties	(220)	
Accretion of discount	2,400	1,361
Plugging and abandonment costs incurred	(1,576)	(1,756)
Revision of previous estimates	(255)	21,276

Future abandonment liability at December 31	$ 53,884	$ 49,569

As of December 31, 2009, $52.4 million of EAC s asset retirement obligations were long-term and recorded in Future abandonment cost, net of current portion and $1.5 million were current and included in Other current liabilities in the accompanying Consolidated Balance Sheets. Approximately $4.7 million of the long-term future abandonment liability represents the estimated cost for decommissioning ENP s Elk Basin natural gas processing plant.

As of December 31, 2009 and 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. These amounts are included in Other assets in the accompanying Consolidated Balance Sheets.

97

ENCORE ACQUISITION COMPANY

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Note 6. Capitalization of Exploratory Well Costs

EAC continues the capitalization of exploratory well costs if the well found a sufficient quantity of reserves to justify its completion as a producing well and the entity is making sufficient progress towards assessing the reserves and the economic and operating viability of the project. The following table reflects the net changes in capitalized exploratory well costs during the periods indicated, and does not include amounts that were capitalized and subsequently expensed in the same period:

	Year Ended December 31, 2009	2008	2007
	(In thousands)		
Beginning balance at January 1	$ 28,757	$ 19,479	$ 13,048
Additions to capitalized exploratory well costs pending the determination of proved reserves	8,241	28,757	19,479
Reclassification to proved property and equipment based on the determination of proved reserves	(15,054)	(19,229)	(9,390)
Previously capitalized exploratory well costs charged to expense	(13,703)	(250)	(3,658)
Ending balance at December 31	$ 8,241	$ 28,757	$ 19,479

All capitalized exploratory well costs have been capitalized for less than one year.

Note 7. Long-Term Debt

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

	Maturity Date	December 31, 2009	2008
		(In thousands)	
Revolving credit facilities	3/7/2012	$ 410,000	$ 725,000
6.25% Senior Subordinated Notes	4/15/2014	150,000	150,000
6.0% Senior Subordinated Notes, net of unamortized discount of $3,449 and $3,960, respectively	7/15/2015	296,551	296,040
9.5% Senior Subordinated Notes, net of unamortized discount of $16,327 and zero, respectively	5/1/2016	208,673	
7.25% Senior Subordinated Notes, net of unamortized discount of $1,127 and $1,229, respectively	12/1/2017	148,873	148,771

Total	$ 1,214,097	$ 1,319,811

Senior Subordinated Notes

In April 2009, EAC issued $225 million of its 9.5% Senior Subordinated Notes due 2016 (the 9.5% Notes) at 92.228 percent of par value. EAC used the net proceeds of approximately $202.4 million, after deducting the underwriters discounts and commissions of $4.5 million, in the aggregate, and offering expenses of approximately $0.6 million to reduce outstanding borrowings under its 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.

As of December 31, 2009, certain of EAC s subsidiaries were subsidiary guarantors of EAC s senior subordinated notes. The subsidiary guarantors may without restriction transfer funds to EAC in the form of

ENCORE ACQUISITION COMPANY

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

cash dividends, loans, and advances. Please read Note 14. Financial Statements of Subsidiary Guarantors for additional discussion.

The indentures governing EAC s senior subordinated notes contain certain affirmative, negative, and financial covenants, which include:

- limitations on incurrence of additional debt, restrictions on asset dispositions, and restricted payments;
- a requirement that EAC maintain a current ratio (as defined in the indentures) of not less than 1.0 to 1.0; and
- a requirement that EAC maintain a ratio of consolidated EBITDA (as defined in the indentures) to consolidated interest expense of not less than 2.5 to 1.0.

As of December 31, 2009, EAC was in compliance with all covenants of its senior subordinated notes.

If EAC experiences a change of control (as defined in the indentures), subject to certain conditions, it must give holders of its senior subordinated notes the opportunity to sell them to EAC at 101 percent of the principal amount, plus accrued and unpaid interest.

Revolving Credit Facilities

Encore Acquisition Company 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. In March 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 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 the 9.5% Notes. The reductions in the borrowing base under the EAC Credit Agreement did not result in any required prepayments of indebtedness. In December 2009, EAC amended the EAC Credit Agreement to, among other things, increase the borrowing base under the EAC Credit Agreement to $925 million. As of December 31, 2009, the borrowing base was $925 million and there were $155 million of outstanding borrowings, $0.3 million of outstanding letters of credit, and $769.7 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 outstanding borrowings 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 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%

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

Table of Contents

ENCORE ACQUISITION COMPANY

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

interests in its restricted subsidiaries. In addition, obligations under the EAC Credit Agreement are guaranteed by EAC s restricted subsidiaries.

Loans under the EAC Credit Agreement are subject to varying rates of interest based on (1) 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 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 London Interbank Offered Rate (LIBOR) 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 including, among others, the following:

- 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 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 December 31, 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;

Table of Contents

ENCORE ACQUISITION COMPANY

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

failure to observe or perform covenants and agreements contained in the EAC 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 EAC or any guarantor under bankruptcy or insolvency law, or the failure of EAC 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

OLLC 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. In March 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. In August 2009, OLLC amended the OLLC Credit Agreement to, among other things, (1) increase the borrowing base from $240 million to $375 million, (2) increase the aggregate commitments of the lenders from $300 million to $475 million, and (3) increase the interest rate margins and commitment fees applicable to loans made under the OLLC Credit Agreement. In November 2009, OLLC amended the OLLC Credit Agreement, which will be effective upon the closing of the Merger, to, among other things, (1) permit the consummation of the Merger from being a Change of Control 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 $475 million. Availability under the OLLC Credit Agreement is subject to a borrowing base, which is redetermined semi-annually and upon requested special redeterminations. As of December 31, 2009, the borrowing base was $375 million and there were $255 million of outstanding borrowings and $120 million of borrowing capacity under the OLLC Credit Agreement.

OLLC incurs a commitment fee of 0.5 percent on the unused portion of the OLLC Credit Agreement.

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, obligations under the OLLC Credit Agreement are guaranteed by ENP and OLLC s restricted subsidiaries. EAC consolidates the debt of ENP with that of its own; however, 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) amount outstanding in relation to the borrowing base and (2) whether the loan is a Eurodollar loan or a base rate loan.

ENCORE ACQUISITION COMPANY

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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 Outstanding Borrowings to Borrowing Base	Applicable Margin for Eurodollar Loans	Applicable Margin for Base Rate Loans
Less than .50 to 1	2.250%	1.250%
Greater than or equal to .50 to 1 but less than .75 to 1	2.500%	1.500%
Greater than or equal to .75 to 1 but less than .90 to 1	2.750%	1.750%
Greater than or equal to .90 to 1	3.000%	2.000%

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 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 including, among others, the following:

- 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 2.5 to 1.0; and
- a requirement that ENP and OLLC maintain a ratio of consolidated funded debt to consolidated adjusted EBITDA of not more than 3.5 to 1.0.

As of December 31, 2009, ENP and OLLC were 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;

Table of Contents

ENCORE ACQUISITION COMPANY

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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.

Long-Term Debt Maturities

The following table shows EAC s long-term debt maturities as of December 31, 2009:

	Payments Due by Period (In thousands)						
	Total	2010	2011	2012	2013	2014	Thereafter
6.25% Notes	$ 150,000	$	$	$	$	$ 150,000	$
6.0% Notes	300,000						300,000
9.5% Notes	225,000						225,000
7.25% Notes	150,000						150,000
Revolving credit facilities	410,000			410,000			
Total	$ 1,235,000	$	$	$ 410,000	$	$ 150,000	$ 675,000

During 2009, 2008, and 2007, the weighted average interest rate for total indebtedness was 5.8 percent, 5.6 percent, and 6.9 percent, respectively.

Table of Contents

ENCORE ACQUISITION COMPANY

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Note 8. Taxes

Income Taxes

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

	Year Ended December 31, 2009	2008	2007
	(In thousands)		
Federal:			
Current	$ (14,638)	$ (7,626)	$ (1,888)
Deferred	55,149	(222,651)	(11,229)
Total federal	40,511	(230,277)	(13,117)
State, net of federal benefit:			
Current	(4,469)	(1,381)	
Deferred	(3,869)	(9,963)	(1,359)
Total state	(8,338)	(11,344)	(1,359)
Income tax benefit (provision)(a)	$ 32,173	$ (241,621)	$ (14,476)

(a) Excludes an excess tax benefit related to stock option exercises and vesting of restricted stock, which was recorded directly to additional paid-in capital, of \$0.3 million and \$2.1 million during 2009 and 2008, respectively. During 2007, EAC did not recognize an excess tax benefit related to stock option exercises and vesting of restricted stock.

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

	Year Ended December 31, 2009	2008	2007
	(In thousands)		
Income (loss) before income taxes	$ (113,308)	$ 672,433	$ 31,631
Noncontrolling interest	(16,752)	54,252	(7,478)

Income (loss) before income taxes and noncontrolling interest	$ (130,060)	$ 726,685	$ 24,153
Income taxes at the Federal statutory rate	$ 45,521	$ (254,340)	$ (8,454)
State income taxes, net of federal benefit	2,943	(12,861)	(716)
Change in estimated future state tax rate	(9,075)	2,113	(495)
Tax on income attributable to noncontrolling interest	(5,863)	18,988	(2,617)
Provision to return adjustment	(1,910)	246	11
Nondeductible deferred compensation expense		(1,124)	(1,963)
Permanent and other	557	5,357	(242)
Income tax benefit (provision)	$ 32,173	$ (241,621)	$ (14,476)

Table of Contents

ENCORE ACQUISITION COMPANY

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

The major components of net current deferred taxes and net long-term deferred taxes were as follows as of the dates indicated:

	December 31, 2009	December 31, 2008
	(In thousands)	
Current:		
Assets:		
Unrealized hedge loss in accumulated other comprehensive loss	$	$ 222
Net operating loss carryforward	1,312	
Other	5,473	2,422
Total current deferred tax assets	6,785	2,644
Liabilities:		
Prepaid insurance	(415)	
Unrealized hedge gain in accumulated other comprehensive loss	(136)	
Derivative fair value gain	(24,923)	(108,412)
Total current deferred tax liabilities	(25,474)	(108,412)
Net current deferred tax liability	$ (18,689)	$ (105,768)
Long-term:		
Assets:		
Alternative minimum tax credits	$ 2,262	$ 2,300
Unrealized hedge loss in accumulated other comprehensive loss	757	735
Derivative fair value loss	40,064	
Tertiary recovery credits	3,385	8,889
Net operating loss carryforward		1,439
Change in accounting method		5,583
Asset retirement obligations	17,575	17,842
Deferred equity-based compensation	9,153	6,757
Acquisition cost capitalized	875	
Other	211	1,556
Total long-term deferred tax assets	74,282	45,101
Liabilities:		
Derivative fair value gain		(2,711)
Book basis of oil and natural gas properties in excess of tax basis	(527,392)	(459,305)

Total long-term deferred tax liabilities	(527,392)	(462,016)
Net long-term deferred tax liability	$ (453,110)	$ (416,915)

At December 31, 2009, EAC had state net operating loss (NOL) carryforwards, which are available to offset future regular state taxable income, if any. At December 31, 2009, EAC also had federal alternative minimum tax (AMT) credits, which are available to reduce future federal regular tax liabilities in excess of AMT. EAC believes it is more likely than not that the NOL carryforwards will offset future taxable income prior to their expiration. The AMT credits have no expiration. Therefore, a valuation allowance against these

ENCORE ACQUISITION COMPANY

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

deferred tax assets is not considered necessary. If unused, these carryforwards and credits will expire as follows:

Expiration Date	Federal AMT Credits	State NOL
	(In thousands)	
2012	$	$ 51
2025		226
2026		152
2027		603
2028		420
Indefinite	2,262	
	$ 2,262	$ 1,452

Note 9. Equity

As discussed in Note 1. Description of Business, on October 31, 2009, EAC entered into the Merger Agreement with Denbury pursuant to which EAC will merge with and into Denbury, with Denbury as the surviving entity. The Merger Agreement provides for Denbury s acquisition of all of the issued and outstanding shares of EAC common stock, par value $.01 per share, in a transaction valued at approximately $4.5 billion, including the assumption of debt and the value of the noncontrolling interest in ENP.

Stock Repurchase Programs

In October 2008, EAC announced that the Board approved a share repurchase program authorizing EAC to repurchase up to $40 million of its common stock. As of December 31, 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 2009, EAC did not repurchase any shares of its outstanding common stock under the share repurchase program. As of December 31, 2009, approximately $22.8 million of EAC s common stock remained authorized for repurchase.

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

Stock Option Exercises and Restricted Stock Vestings

During 2009, 2008, and 2007, certain employees exercised 23,105 options, 45,616 options, and 128,709 options, respectively, for which EAC received proceeds of $0.5 million, $0.5 million, and $1.6 million, respectively. During

2009, 2008, and 2007, certain employees elected to satisfy minimum tax withholding obligations in conjunction with the vesting of restricted stock by directing EAC to withhold 111,819 shares, 32,946 shares, and 38,978 shares of common stock, respectively, which are accounted for as treasury stock until they are formally retired. Please read Note 11. Employee Benefit Plans for additional discussion of EAC s stock option exercises and restricted stock vestings.

Preferred Stock

EAC s authorized capital stock includes 5,000,000 shares of preferred stock, none of which were issued and outstanding at December 31, 2009 or 2008. EAC does not plan to issue any shares of preferred stock.

ENCORE ACQUISITION COMPANY

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Issuance of EAC Common Stock

In September 2009, EAC issued 2,750,000 shares of common stock under its shelf registration statement at a price to the public of $37.40 per common share. EAC used the net proceeds of approximately $100.6 million, after deducting the underwriters discounts and commissions of $2.0 million, in the aggregate, and offering costs of approximately $0.2 million, to reduce outstanding borrowings under the EAC Credit Agreement.

Issuances 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. As a result, EAC s ownership of ENP s common units decreased from approximately 58 percent to approximately 46 percent. Additionally, EAC increased Noncontrolling interest and Additional paid-in capital on the accompanying Consolidated Balance Sheets by $20.3 million to recognize gains on the issuance of ENP s common units.

In May 2009, ENP issued 2,760,000 common units at a price to the public of $15.60 per common unit. As a result, EAC s ownership 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 $9.3 million to recognize gains on the issuance of ENP s common units.

In May 2008, ENP acquired an existing net profits interest in certain of its properties in the Permian Basin of West Texas in exchange for 283,700 common units which were valued at $5.8 million at the time of the acquisition. As a result, EAC s ownership of ENP s common units decreased from approximately 67 percent to approximately 66 percent. Additionally, EAC increased Noncontrolling interest and Additional paid-in capital on the accompanying Consolidated Balance Sheets by $3.5 million to recognize gains on the issuance of ENP s common units.

In December 2008, as a result of the conversion of ENP s management incentive units into ENP common units, EAC recorded a $13.9 million economic uniformity adjustment by reducing Additional paid-in capital and increasing Noncontrolling interest in the accompanying Consolidated Balance Sheets.

In September 2007, ENP completed its IPO of 9,000,000 common units at a price to the public of $21.00 per unit, and in October 2007, the underwriters exercised their over-allotment option to purchase an additional 1,148,400 common units. As a result, EAC s ownership of ENP s common units decreased from 100 percent to approximately 58 percent. Additionally, EAC increased Noncontrolling interest and Additional paid-in capital on the accompanying Consolidated Balance Sheets by $77.6 million to recognize gains on the issuance of ENP s common units.

Table of Contents

ENCORE ACQUISITION COMPANY

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

The following table summarizes EAC s change of ownership in ENP since December 31, 2007:

	ENP Common Units Owned			EAC% of ENP Common Units	ENP GP Units Owned by EAC	EAC % of All ENP Units
Date	EAC	Others	Total			
12/31/2007	14,039,279	10,148,400	24,187,679	58.0%	504,851	58.9%
Issuance of common units in acquisition of Permian and Williston Basin Assets	6,884,776		6,884,776			
2/7/2008	20,924,055	10,148,400	31,072,455	67.3%	504,851	67.9%
Issuance of common units in acquisition of net profits interest		283,700	283,700			
5/1/2008	20,924,055	10,432,100	31,356,155	66.7%	504,851	67.3%
Vesting of phantom units		6,250	6,250			
10/31/2008	20,924,055	10,438,350	31,362,405	66.7%	504,851	67.2%
Conversion of management incentive units		1,715,205	1,715,205			
12/31/2008	20,924,055	12,153,555	33,077,610	63.3%	504,851	63.8%
Common unit offering		2,760,000	2,760,000			
5/22/2009	20,924,055	14,913,555	35,837,610	58.4%	504,851	59.0%
Common unit offering		9,430,000	9,430,000			
7/22/2009	20,924,055	24,343,555	45,267,610	46.2%	504,851	46.8%
Vesting of phantom units		12,500	12,500			
10/30/2009	20,924,055	24,356,055	45,280,110	46.2%	504,851	46.8%
Conversion of management		5,237	5,237			

incentive units						
12/31/2009	20,924,055	24,361,292	45,285,347	46.2%	504,851	46.8%

Rights Plan

In October 2008, the Board declared a dividend of one right for each outstanding share of EAC s common stock to stockholders of record at the close of business on November 7, 2008. Each right entitles the registered holder to purchase from EAC a unit consisting of one one-hundredth of a share of Series A Junior Participating Preferred Stock, par value $0.01 per share, at a purchase price of $120 per fractional share, subject to adjustment.

The rights will separate from the common stock and a Distribution Date will occur, with certain exceptions, upon the earlier of (1) ten days following a public announcement that a person or group of affiliated or associated persons (an Acquiring Person) has acquired, or obtained the right to acquire, beneficial ownership of more than 10 percent of EAC s then-outstanding shares of common stock, or (2) ten business days following the commencement of a tender offer or exchange offer that would result in a person s becoming an Acquiring Person. In certain circumstances, the Distribution Date may be deferred by the Board. The rights are not exercisable until the Distribution Date and will expire at the close of business on October 28, 2011, unless earlier redeemed or exchanged by EAC.

EAC amended its rights plan in connection with its entrance into the Merger Agreement.

108

Table of Contents

ENCORE ACQUISITION COMPANY

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Note 10. Earnings Per Share

As discussed in Note 2. Summary of Significant Accounting Policies, EAC adopted ASC 260-10 on January 1, 2009, and all periods prior to adoption have been restated to calculate earnings per share in accordance therewith. For 2008, basic earnings per share and diluted earnings per share were decreased by $0.14 and $0.06, respectively, as a result of the adoption of ASC 260-10. For 2007, diluted earnings per share was decreased by $0.01 as a result of the adoption of ASC 260-10. For 2007, basic earnings per share was unaffected by the adoption of ASC 260-10.

The following table reflects the allocation of net income (loss) to EAC s common stockholders and earnings per share computations for the periods indicated:

	Year Ended December 31,		
	2009	2008	2007
	(In thousands, except per share amounts)		
Basic Earnings Per Share			
Numerator:			
Undistributed net income (loss) attributable to EAC	$ (81,135)	$ 430,812	$ 17,155
Participation rights of unvested restricted stock in undistributed earnings(a)		(7,595)	(291)
Basic undistributed net income (loss) attributable to EAC common shares	$ (81,135)	$ 423,217	$ 16,864
Denominator:			
Basic weighted average shares outstanding	52,634	52,270	53,170
Basic EPS attributable to EAC common shares	$ (1.54)	$ 8.10	$ 0.32
Diluted Earnings Per Share			
Numerator:			
Undistributed net income (loss) attributable to EAC	$ (81,135)	$ 430,812	$ 17,155
Participation rights of unvested restricted stock in undistributed earnings(a)		(7,511)	(289)
Diluted undistributed net income (loss) attributable to EAC common shares	$ (81,135)	$ 423,301	$ 16,866
Denominator:			
Basic weighted average shares outstanding	52,634	52,270	53,170
Effect of dilutive options(b)		596	459

Diluted weighted average shares outstanding		52,634		52,866		53,629
Diluted EPS attributable to EAC common shares	$	(1.54)	$	8.01	$	0.31

(a) Unvested restricted stock has no contractual obligation to absorb losses of EAC. Therefore, for 2009, 920,122 shares of restricted stock were outstanding but were excluded from the earnings per share calculations because their effect would have been antidilutive. Please read Note 11. Employee Benefit Plans for additional discussion of restricted stock.

(b) For 2009, 2008, and 2007, options to purchase 1,729,591, 157,614, and 121,651 shares of common stock, respectively, were outstanding but were excluded from the earnings per share calculations because their effect would have been antidilutive. Please read Note 11. Employee Benefit Plans for additional discussion of stock options.

ENCORE ACQUISITION COMPANY

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Note 11. Employee Benefit Plans

401(k) Plan

EAC made contributions to its 401(k) plan, which is a voluntary and contributory plan for eligible employees based on a percentage of employee contributions, of $4.5 million, $3.6 million, and $2.2 million during 2009, 2008, and 2007, respectively. EAC s 401(k) plan does not allow employees to invest in securities of EAC.

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 1,600,000 are available for grants of full value stock awards, such as restricted stock or stock units. As of December 31, 2009, there were 1,717,787 shares available for issuance under the 2008 Plan, of which 1,182,586 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.

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 grant date fair value in excess of $5.0 million.

During 2009, 2008, and 2007, EAC recorded non-cash stock-based compensation expense related to its incentive stock plans of $12.3 million, $9.0 million, and $9.2 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 2009, 2008, and 2007, EAC also capitalized $2.4 million, $2.3 million, and $1.3 million, respectively, of non-cash stock-based compensation expense related to its incentive stock plans as a component of Proved properties, including wells and related equipment in the accompanying Consolidated Balance Sheets. During 2009, 2008, and 2007, EAC recognized income tax benefits related to its incentive stock plans of $4.6 million, $3.4 million, and $3.4 million, respectively.

Table of Contents

ENCORE ACQUISITION COMPANY

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Please read Note 15. 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 2009, 2008, and 2007 was estimated on the grant date using a Black-Scholes option valuation model based on the following assumptions:

	Year Ended December 31, 2009	2008	2007
Expected volatility	51.9%	33.7%	35.7%
Expected dividend yield	0.0%	0.0%	0.0%
Expected term (in years)	6.25	6.25	6.0
Risk-free interest rate	2.1%	3.0%	4.8%
Weighted-average grant-date fair value per share	$ 15.81	$ 13.15	$ 11.16

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 term 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 periods indicated:

	Year Ended December 31, 2009				2008		2007	
	Number of Options	Weighted Average Strike Price	Weighted Average Remaining Contractual Term	Aggregate Intrinsic Value (In thousands)	Number of Options	Weighted Average Strike Price	Number of Options	Weighted Average Strike Price
Outstanding at beginning of year	1,497,413	$ 18.02			1,381,782	$ 16.03	1,337,118	$ 14.44
Granted	269,417	30.55			176,170	33.76	200,059	25.73
Forfeited or expired	(14,134)	30.93			(14,923)	30.83	(26,686)	27.15
Exercised	(23,105)	20.17			(45,616)	14.11	(128,709)	12.34
	1,729,591	19.84	4.9	$ 48,738	1,497,413	18.02	1,381,782	16.03

Outstanding at end of year								
Exercisable at end of year	1,298,056	16.23	3.6	41,262	1,177,015	14.65	1,103,018	13.25

The total intrinsic value of options exercised during 2009, 2008, and 2007 was $0.3 million, $1.6 million, and $2.3 million, respectively. During 2009, 2008, and 2007, EAC received proceeds from the exercise of stock options of $0.5 million, $0.5 million, and $1.6 million, respectively. During 2009 and 2008, EAC recognized income tax benefits related to stock options of $38 thousand and $0.5 million, respectively. During 2007, EAC did not recognize any income tax benefits related to stock options. At December 31, 2009, EAC had $1.7 million of total unrecognized compensation cost related to unvested stock options, which is expected to be recognized over a weighted average period of 1.9 years.

Table of Contents

ENCORE ACQUISITION COMPANY

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Additional information about options outstanding and exercisable at December 31, 2009 is as follows:

Year of Grant	Range of Strike Prices Per Share	Weighted Number of Options Outstanding	Average Life (Years)	Weighted Average Strike Price	Number of Options Exercisable
2001	$8.33 to $9.33	400,236	1.5	$ 8.87	400,236
2002	$8.50 to $12.40	283,836	2.8	11.94	283,836
2003	$11.49 to $13.61	35,127	3.5	12.25	35,127
2004	$17.17 to $19.77	259,075	4.1	17.55	259,075
2005	$26.55	66,676	5.1	$ 26.55	66,676
2006	$31.10	87,961	6.1	$ 31.10	87,961
2007	$25.73	173,997	7.1	$ 25.73	115,170
2008	$33.76	157,884	8.1	$ 33.76	49,975
2009	$30.55	264,799	9.1	$ 30.55	
		1,729,591			1,298,056

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. The weighted-average grant-date fair value of restricted stock awards granted during 2009, 2008, and 2007 was $30.52 per share, $37.02 per share, and $25.95 per share, respectively. During 2009, 2008, and 2007, EAC recognized expense related to restricted stock of $9.5 million, $7.6 million, and $7.6 million, respectively. During 2009, EAC recognized income tax provisions related to the vesting of restricted stock of $0.4 million. During 2008, EAC recognized income tax benefits related to the vesting of restricted stock of $1.6 million. During 2007, EAC did not recognize any income tax benefits related to the vesting of restricted stock. The following table summarizes the changes in EAC s unvested restricted stock awards for 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	(22,256)	30.31
Outstanding at December 31, 2009	920,122	31.20

During 2009, 2008, and 2007, EAC issued 189,109 shares, 241,515 shares, and 169,453 shares, respectively, of restricted stock to employees and members of the Board, the vesting of which is dependent only on the passage of time and continued employment. The following table provides information regarding EAC s outstanding restricted stock at December 31, 2009 the vesting of which is dependent only on the passage of time and continued employment:

	Year of Vesting				
Year of Grant	**2010**	**2011**	**2012**	**2013**	**Total**
2005	69,592				69,592
2006	59,377				59,377
2007	77,186	77,143	4,166		158,495
2008	67,494	91,417	67,333		226,244
2009	46,987	46,889	46,806	46,712	187,394
Total	320,636	215,449	118,305	46,712	701,102

Table of Contents

ENCORE ACQUISITION COMPANY

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

During 2009, 2008, and 2007, EAC issued 223,340 shares, 72,571 shares, and 175,180 shares of restricted stock to certain members of senior management, the vesting of which is dependent not only on the passage of time and continued employment, but also on the achievement of certain performance measures. The performance measures related to the 2008 and 2007 awards were met and therefore, vesting depends only on the passage of time and continued employment and therefore, are included in the table above. The following table provides information regarding EAC s outstanding restricted stock at December 31, 2009 the vesting of which is dependent not only on the passage of time and continued employment, but also on the achievement of certain performance measures:

	Year of Vesting				
Year of Grant	**2010**	**2011**	**2012**	**2013**	**Total**
2009	54,755	54,755	54,755	54,755	219,020

None of EAC s unvested restricted stock is subject to variable accounting. During 2009, 2008, and 2007, there were 408,478 shares, 256,785 shares, and 184,867 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, 32,946 shares, and 38,978 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 2009, 2008, and 2007 was $11.0 million, $8.7 million, and $5.3 million, respectively. As of December 31, 2009, EAC had $8.4 million of total unrecognized compensation cost related to unvested restricted stock, which is expected to be recognized over a weighted average period of 2.7 years.

ENCORE ACQUISITION COMPANY

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Note 12. Fair Value Measurements

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

	December 31,			
	2009		2008	
	Book Value	Fair Value	Book Value	Fair Value
	(In thousands)			
Assets:				
Cash and cash equivalents	$ 13,958	$ 13,958	$ 2,039	$ 2,039
Accounts receivable, net	114,872	114,872	117,995	117,995
Plugging bond	874	991	824	1,202
Bell Creek escrow	9,263	9,263	9,229	9,241
Commodity derivative contracts	61,031	61,031	387,841	387,841
Long-term receivables, net	65,939	65,939	71,986	71,986
Liabilities:				
Accounts payable	7,138	7,138	10,017	10,017
6.25% Senior Subordinated Notes	150,000	146,625	150,000	101,250
6.0% Senior Subordinated Notes	296,551	300,375	296,040	194,250
9.5% Senior Subordinated Notes	208,673	231,750		
7.25% Senior Subordinated Notes	148,873	150,000	148,771	94,500
Revolving credit facilities	410,000	410,000	725,000	725,000
Commodity derivative contracts	60,166	60,166	229	229
Deferred premiums on commodity derivative contracts	48,821	48,821	67,610	67,610
Interest rate swaps	3,669	3,669	4,559	4,559

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 in the accompanying Consolidated Balance Sheets and are classified as held to maturity and therefore, are recorded at amortized cost. The fair values of the plugging bond, Bell Creek escrow, and senior subordinated notes were determined using open market quotes. The difference between book value and fair value of the senior subordinated notes 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. EAC s and ENP s credit risk have not changed materially from the date the revolving credit facilities were entered into. Commodity derivative contracts and interest rate swaps are marked-to-market each period and are thus stated at fair value in the accompanying Consolidated Balance Sheets. 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.

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.

ENCORE ACQUISITION COMPANY

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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 some 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 additional 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 wanted 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 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 December 31, 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)
2010							$ (30,760)
	880	$ 80.00	2,940	$ 90.57		$	
	5,500	73.47	3,000	74.13	3,885	77.79	
	8,385	62.83	500	65.60	1,750	64.08	
	1,000	56.00			1,000	59.70	
2011							17,720
	4,880	80.00	2,940	94.44	325	80.00	
	2,500	70.00			1,060	78.42	
	4,385	65.00			250	69.65	
2012							(5,120)
	750	70.00	500	82.05	835	81.19	
	2,135	65.00	250	79.25	1,300	76.54	
							$ (18,160)

ENCORE ACQUISITION COMPANY

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Natural Gas Derivative Contracts

Period	Average Daily Floor Volume (Mcf)	Weighted Average Floor Price (per Mcf)	Average Daily Cap Volume (Mcf)	Weighted Average Cap Price (per Mcf)	Average Daily Swap Volume (Mcf)	Weighted Average Swap Price (per Mcf)	Asset Fair Market Value (In thousands)
Jan. June 2010							$ 5,949
	3,800	$ 8.20	3,800	$ 9.58	25,452	$ 6.46	
	4,698	7.26			20,550	5.23	
July Dec. 2010							6,644
	3,800	8.20	3,800	9.58			
	4,698	7.26	10,000	6.25	25,452	6.46	
	10,000	5.13			550	5.86	
2011							4,677
	3,398	6.31			27,952	6.48	
					550	5.86	
2012							1,755
	898	6.76			25,452	6.47	
					550	5.86	
							$ 19,025

As of December 31, 2009, EAC had $48.8 million of deferred premiums payable, of which $26.3 million was long-term and included in Derivatives in the non-current liabilities section of the accompanying Consolidated Balance Sheet and $22.5 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 January 2010 to January 2013.

Counterparty Risk. At December 31, 2009, EAC had committed 10 percent or greater (in terms of fair market value) of either its oil or natural gas derivative contracts in asset positions to the following counterparties:

Counterparty	Fair Market Value of Oil Derivative Contracts Committed (In thousands)	Fair Market Value of Natural Gas Derivative Contracts Committed (In thousands)
BNP Paribas	$ 22,570	$ 7,496
Calyon	(a)	8,550

JP Morgan	10,272	(a)
Royal Bank of Canada	14,059	(a)
Wachovia	8,302	3,844

(a) Less than 10 percent.

In order to mitigate the credit risk of financial instruments, EAC enters into master netting agreements with certain 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 is intended to benefit 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

ENCORE ACQUISITION COMPANY

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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 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 December 31, 2009, all of which were entered into with Bank of America, N.A.:

Term	Notional Amount (In thousands)	Fixed Rate	Floating Rate
Jan. 2010 - Jan. 2011	$ 50,000	3.1610%	1-month LIBOR
Jan. 2010 - Jan. 2011	25,000	2.9650%	1-month LIBOR
Jan. 2010 - Jan. 2011	25,000	2.9613%	1-month LIBOR
Jan. 2010 - Mar. 2012	50,000	2.4200%	1-month LIBOR

During 2009 and 2008, settlements of interest rate swaps increased EAC s consolidated interest expense by approximately $3.8 million and $0.2 million, respectively.

Current Period Impact. As a result of commodity derivative contracts which were previously designated as hedges, EAC recognized a pre-tax reduction in oil and natural gas revenues of approximately $2.9 million and $53.6 million in 2008 and 2007, respectively. EAC also recognizes 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 (gain) for the periods indicated:

	Year Ended December 31, 2009	2008	2007
	(In thousands)		
Ineffectiveness	$ 2	$ 372	$
Mark-to-market loss (gain)	350,365	(365,495)	36,272
Premium amortization	98,395	62,352	41,051
Settlements	(389,165)	(43,465)	35,160
Total derivative fair value loss (gain)	$ 59,597	$ (346,236)	$ 112,483

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 the EAC

Credit Agreement.

Accumulated Other Comprehensive Loss. At December 31, 2009 and 2008, Accumulated other comprehensive loss on the accompanying Consolidated Balance Sheets consisted entirely of deferred losses, net of tax, on ENP s interest rate swaps of $1.0 million and $1.7 million, respectively. During 2010, EAC expects to reclassify $3.4 million of deferred losses from accumulated other comprehensive loss to interest expense. EAC also expects to reclassify $0.1 million of income taxes from accumulated other comprehensive loss to income tax provision during 2010. The actual gains or losses ENP will realize from its interest rate swaps may vary significantly from the deferred losses recorded in Accumulated other comprehensive loss in the accompanying Consolidated Balance Sheet due to the fluctuation of interest rates.

Table of Contents

ENCORE ACQUISITION COMPANY

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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			
	December 31, 2009		December 31, 2008		December 31, 2009		December 31, 2(	
	Balance Sheet Location	Fair Value	Balance Sheet Location	Fair Value	Balance Sheet Location	Fair Value	Balance Sheet Location	I V
tives not ated as g nents ASC 815								
odity ve ts	Derivatives - current	$ 25,825	Derivatives - current	$ 349,344	Derivatives - current	$ 43,993	Derivatives - current	$
odity ve ts	Derivatives - noncurrent	35,206	Derivatives -noncurrent	38,497	Derivatives - noncurrent	16,173	Derivatives - noncurrent	
erivatives ignated as g nents ASC 815		$ 61,031		$ 387,841		$ 60,166		$
tives ated as g nents ASC 815								
rate swaps	Derivatives - current	$	Derivatives - current	$	Derivatives - current	$ 3,421	Derivatives - current	$
rate swaps	Derivatives - noncurrent		Derivatives -noncurrent		Derivatives - noncurrent	248	Derivatives - noncurrent	

erivatives ated as g nents ASC 815	$	$	$ 3,669	$
erivatives	$ 61,031	$ 387,841	$ 63,835	$

The following table summarizes the effect of derivative instruments not designated as hedges under ASC 815 on the Consolidated Statements of Operations for the periods indicated (in thousands):

Derivatives Not Designated as Hedges Under ASC 815	**Location of Loss (Gain) Recognized In Income**	**Amount of Loss (Gain) Recognized In Income Year Ended December 31, 2009**	**2008**	**2007**
Commodity derivative contracts	Derivative fair value loss (gain)	$ 59,595	$ (346,608)	$ 112,483

The following tables summarize the effect of derivative instruments designated as hedges under ASC 815 on the Consolidated Statements of Operations for the periods indicated (in thousands):

Derivatives Designated as Hedges Under ASC 815	**Amount of Loss Recognized in Accumulated OCI (Effective Portion) Year Ended December 31, 2009**	**2008**	**2007**
Interest rate swaps	$ 3,075	$ 3,065	$

Location of Loss Reclassified from Accumulated OCI into Income (Effective Portion)	**Amount of Loss Reclassified from Accumulated OCI into Income (Effective Portion) Year Ended December 31, 2009**	**2008**	**2007**
Interest expense	$ 3,785	$ 246	$
Oil and natural gas revenues		2,857	53,587
	$ 3,785	$ 3,103	$ 53,587

Amount of Loss Recognized In Income as Ineffective Year Ended December 31,

Location of Loss Recognized in Income as Ineffective	2009	2008	2007
Derivative fair value loss (gain)	$ 2	$ 372	$

ENCORE ACQUISITION COMPANY

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Fair Value Hierarchy

ASC 820-10 established a fair value hierarchy that prioritizes the inputs used to measure fair value. The three levels of the fair value hierarchy defined by ASC 820-10 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-based 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 input of EAC s valuation model is 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 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 were 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.

Table of Contents

ENCORE ACQUISITION COMPANY

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

The following table sets forth EAC s assets and liabilities that were accounted for at fair value on a recurring basis as of December 31, 2009:

Description	Asset (Liability) at December 31, 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	$ (38,149)	$	$ (38,149)	$
Oil derivative contracts floors and caps	19,989			19,989
Natural gas derivative contracts swaps	11,026		11,026	
Natural gas derivative contracts floors and caps	7,999			7,999
Interest rate swaps	(3,669)		(3,669)	
Total	$ (2,804)	$	$ (30,792)	$ 27,988

The following table summarizes the changes in the fair value of EAC s Level 3 assets and liabilities for 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		(7,223)		23,736		16,513
Purchases		9,012		844		9,856
Settlements		(319,135)		(29,322)		(348,457)
Balance at December 31, 2009	$	19,989	$	7,999	$	27,988
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	$	(7,223)	$	23,736	$	16,513

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 (gain) in the accompanying Consolidated Statements of Operations.

All fair values have been adjusted for nonperformance risk resulting in a reduction of the net commodity derivative asset of approximately $0.2 million as of December 31, 2009. For commodity derivative contracts which are in an asset position, EAC uses the counterparty s credit default swap rating. For commodity derivative contracts which are in a liability position, EAC uses the average credit default swap rating of its peer companies as EAC does not have its own credit default swap rating.

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

ENCORE ACQUISITION COMPANY

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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 5. Asset Retirement Obligations for additional discussion of EAC s asset retirement obligations.

The following table sets forth EAC s assets and liabilities that were accounted for at fair value on a nonrecurring basis as of December 31, 2009:

		Fair Value Measurements Using			
		Quoted Prices in Active Markets for Identical Assets	Significant Other Observable Inputs	Significant Unobservable Inputs	Total Gains
Description	**Liability at December 31, 2009**	**(Level 1)**	**(Level 2)**	**(Level 3)**	**(Losses)**
			(In thousands)		
Asset retirement obligations	$ 3,966	$	$	$ 3,966	$

Note 13. Related Party Transactions

During 2008 and 2007, EAC received approximately $160.5 million and $85.3 million, respectively, from affiliates of Tesoro Corporation (Tesoro) related to gross oil and natural gas production sold from wells operated by Encore Operating. Mr. John V. Genova, a member of the Board, served as an employee of Tesoro until May 2008.

Please read Note 15. ENP for a discussion of related party transactions with ENP.

Note 14. 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 December 31, 2009 and 2008 and Condensed Consolidating Statements of Operations and Comprehensive Income (Loss) and Condensed Consolidating Statements of Cash Flows for the years ended December 31, 2009, 2008, and 2007 present consolidating financial information for Encore Acquisition Company (Parent) on a stand alone, unconsolidated basis, and its combined guarantor and combined non-guarantor subsidiaries. As of December 31, 2009, EAC s guarantor subsidiaries were:

EAP Properties, Inc.;

EAP Operating, LLC;

Encore Operating, L.P.; and

Encore Operating Louisiana, LLC.

As of December 31, 2009, EAC s non-guarantor subsidiaries were:

ENP;

OLLC;

GP LLC;

ENCORE ACQUISITION COMPANY

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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, and revenues and expenses between the Parent, guarantor subsidiaries, and non-guarantor subsidiaries are shown prior to consolidation with the Parent and then eliminated to arrive at consolidated totals per the accompanying consolidated financial statements. Prior periods have not been adjusted for ENP s acquisitions from EAC. Please read Note 15. ENP for a discussion of transactions with ENP.

Table of Contents

ENCORE ACQUISITION COMPANY

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

CONDENSED CONSOLIDATING BALANCE SHEET
December 31, 2009

	Parent	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Eliminations	Consolidated Total
			(In thousands)		
ASSETS					
Current assets:					
Cash and cash equivalents	$ 567	$ 11,637	$ 1,754	$	$ 13,958
Other current assets	2,314	145,747	46,494	(10,994)	183,561
Total current assets	2,881	157,384	48,248	(10,994)	197,519
Properties and equipment, at cost successful efforts method:					
Proved properties, including wells and related equipment		3,352,789	851,833		4,204,622
Unproved properties		95,546	55		95,601
Accumulated depletion, depreciation, and amortization		(847,850)	(210,417)		(1,058,267)
		2,600,485	641,471		3,241,956
Other property and equipment, net		15,018	444		15,462
Other assets, net	16,370	163,290	29,488	(124)	209,024
Investment in subsidiaries	2,812,831	(8,742)		(2,804,089)	
Total assets	$ 2,832,082	$ 2,927,435	$ 719,651	$ (2,815,207)	$ 3,663,961
LIABILITIES AND EQUITY					
Current liabilities	$ 43,841	$ 194,836	$ 32,690	$ (10,994)	$ 260,373
Deferred taxes	453,225	9		(124)	453,110
Long-term debt	959,097		255,000		1,214,097
Other liabilities		79,591	25,957		105,548
Total liabilities	1,456,163	274,436	313,647	(11,118)	2,033,128
Commitments and contingencies (see Note 4)					

Total equity	1,375,919	2,652,999	406,004	(2,804,089)	1,630,833
Total liabilities and equity	$ 2,832,082	$ 2,927,435	$ 719,651	$ (2,815,207)	$ 3,663,961

Table of Contents

ENCORE ACQUISITION COMPANY

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

CONDENSED CONSOLIDATING BALANCE SHEET
December 31, 2008

	Parent	Guarantor Subsidiaries	Non-Guarantor Subsidiaries (In thousands)	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 4)					

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

Table of Contents

ENCORE ACQUISITION COMPANY

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

CONSOLIDATING STATEMENT OF OPERATIONS AND COMPREHENSIVE INCOME (LOSS)
For the Year Ended December 31, 2009

	Parent	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Eliminations	Consolidated Total
			(In thousands)		
Revenues:					
Oil	$	$ 421,780	$ 127,611	$	$ 549,391
Natural gas		108,757	22,428		131,185
Marketing		4,362	478		4,840
Total revenues		534,899	150,517		685,416
Expenses:					
Production:					
Lease operating		123,386	41,676		165,062
Production, ad valorem, and severance taxes		53,440	16,099		69,539
Depletion, depreciation, and amortization		234,019	56,757		290,776
Impairment of long-lived assets		9,979			9,979
Exploration		49,356	3,132		52,488
General and administrative	19,771	28,445	11,378	(5,570)	54,024
Marketing		3,692	302		3,994
Derivative fair value loss		12,133	47,464		59,597
Provision for doubtful accounts		7,686			7,686
Other operating	206	22,456	3,099		25,761
Total expenses	19,977	544,592	179,907	(5,570)	738,906
Operating income (loss)	(19,977)	(9,693)	(29,390)	5,570	(53,490)
Other income (expenses):					
Interest	(68,043)		(10,974)		(79,017)
Equity income from subsidiaries	(25,035)	(12,064)		37,099	
Other	(228)	8,199	46	(5,570)	2,447
Total other expenses	(93,306)	(3,865)	(10,928)	31,529	(76,570)
Income (loss) before income taxes	(113,283)	(13,558)	(40,318)	37,099	(130,060)

Income tax benefit (provision)	32,070	117	(14)		32,173
Consolidated net income (loss)	(81,213)	(13,441)	(40,332)	37,099	(97,887)
Change in deferred hedge loss on interest rate swaps, net of tax	(339)		839		500
Consolidated comprehensive income (loss)	$ (81,552)	$ (13,441)	$ (39,493)	$ 37,099	$ (97,387)

Table of Contents

ENCORE ACQUISITION COMPANY

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

CONSOLIDATING STATEMENT OF OPERATIONS AND COMPREHENSIVE INCOME
For the Year Ended December 31, 2008

	Parent	Guarantor Subsidiaries	Non-Guarantor Subsidiaries (In thousands)	Eliminations	Consolidated Total
Revenues:					
Oil	$	$ 749,864	$ 147,579	$	$ 897,443
Natural gas		192,942	34,537		227,479
Marketing		5,172	5,324		10,496
Total revenues		947,978	187,440		1,135,418
Expenses:					
Production:					
Lease operating		146,460	28,655		175,115
Production, ad valorem, and severance taxes		91,809	18,835		110,644
Depletion, depreciation, and amortization		190,548	37,704		228,252
Impairment of long-lived assets		59,526			59,526
Exploration		39,026	181		39,207
General and administrative	15,801	24,751	12,135	(4,266)	48,421
Marketing		4,104	5,466		9,570
Derivative fair value gain		(249,356)	(96,880)		(346,236)
Provision for doubtful accounts		1,984			1,984
Other operating	165	11,485	1,325		12,975
Total expenses	15,966	320,337	7,421	(4,266)	339,458
Operating income (loss)	(15,966)	627,641	180,019	4,266	795,960
Other income (expenses):					
Interest	(66,204)		(6,969)		(73,173)
Equity income from subsidiaries	736,408	51,468		(787,876)	
Other	98	7,967	99	(4,266)	3,898
Total other expenses	670,302	59,435	(6,870)	(792,142)	(69,275)
Income before income taxes	654,336	687,076	173,149	(787,876)	726,685
Income tax provision	(240,986)		(635)		(241,621)

Consolidated net income	413,350	687,076	172,514	(787,876)	485,064
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	(625)		(2,692)		(3,317)
Comprehensive income	$ 411,654	$ 689,933	$ 169,822	$ (787,876)	$ 483,533

Table of Contents

ENCORE ACQUISITION COMPANY

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

CONSOLIDATING STATEMENT OF OPERATIONS AND COMPREHENSIVE INCOME (LOSS)
For the Year Ended December 31, 2007

	Parent	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Eliminations	Consolidated Total
			(In thousands)		
Revenues:					
Oil	$	$ 503,981	$ 58,836	$	$ 562,817
Natural gas		137,838	12,269		150,107
Marketing		33,439	8,582		42,021
Total revenues		675,258	79,687		754,945
Expenses:					
Production:					
Lease operating		129,506	13,920		143,426
Production, ad valorem, and severance taxes		66,014	8,571		74,585
Depletion, depreciation, and amortization		157,982	25,998		183,980
Exploration		27,726			27,726
General and administrative	15,107	15,354	10,707	(2,044)	39,124
Marketing		33,876	6,673		40,549
Derivative fair value loss		86,182	26,301		112,483
Provision for doubtful accounts		5,816			5,816
Other operating	221	16,083	762		17,066
Total expenses	15,328	538,539	92,932	(2,044)	644,755
Operating income (loss)	(15,328)	136,719	(13,245)	2,044	110,190
Other income (expenses):					
Interest	(82,825)	(6,415)	(12,294)	12,830	(88,704)
Equity income (loss) from subsidiaries	123,381	(3,205)		(120,176)	
Other	6,405	10,940	196	(14,874)	2,667
Total other expenses	46,961	1,320	(12,098)	(122,220)	(86,037)
Income (loss) before income taxes	31,633	138,039	(25,343)	(120,176)	24,153
Income tax benefit (provision)	(14,478)		2		(14,476)

Consolidated net income (loss)		17,155		138,039		(25,341)		(120,176)		9,677
Amortization of deferred loss on commodity derivative contracts, net of tax		(20,047)		53,588						33,541
Comprehensive income (loss)	$	(2,892)	$	191,627	$	(25,341)	$	(120,176)	$	43,218

127

Table of Contents

ENCORE ACQUISITION COMPANY

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

CONDENSED CONSOLIDATING STATEMENT OF CASH FLOWS
For the Year Ended December 31, 2009

	Parent	Guarantor Subsidiaries	Non-Guarantor Subsidiaries (In thousands)	Eliminations	Consolidated Total
Cash flows from operating activities:					
Net cash provided by (used in) operating activities	$ (71,908)	$ 702,614	$ 114,971	$	$ 745,677
Cash flows from investing activities:					
Acquisition of oil and natural gas properties		(400,997)	(31,960)		(432,957)
Development of oil and natural gas properties		(333,261)	(9,037)		(342,298)
Investments in subsidiaries	178,435			(178,435)	
Other		5,913	(88)		5,825
Net cash provided by (used in) investing activities	178,435	(728,345)	(41,085)	(178,435)	(769,430)
Cash flows from financing activities:					
Proceeds from long-term debt, net of issuance costs	405,105		227,061		632,166
Payments on long-term debt	(625,000)		(125,000)		(750,000)
Proceeds from issuance of EAC common stock, net of offering costs	100,608				100,608
Proceeds from issuance of ENP common units, net of offering costs			170,088		170,088
Net equity contributions (distributions)		84,221	(262,656)	178,435	
Other	12,720	(47,666)	(82,244)		(117,190)
Net cash provided by (used in) financing activities	(106,567)	36,555	(72,751)	178,435	35,672
	(40)	10,824	1,135		11,919

Increase (decrease) in cash and cash equivalents										
Cash and cash equivalents, beginning of period		607		813		619				2,039
Cash and cash equivalents, end of period	$	567	$	11,637	$	1,754	$		$	13,958

128

Table of Contents

ENCORE ACQUISITION COMPANY

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

CONDENSED CONSOLIDATING STATEMENT OF CASH FLOWS
For the Year Ended December 31, 2008

	Parent	Guarantor Subsidiaries	Non-Guarantor Subsidiaries (In thousands)	Eliminations	Consolidated Total
Cash flows from operating activities:					
Net cash provided by (used in) operating activities	$ 629,345	$ (81,882)	$ 115,774	$	$ 663,237
Cash flows from investing activities:					
Acquisition of oil and natural gas properties		(142,471)	(88)		(142,559)
Development of oil and natural gas properties		(543,399)	(17,598)		(560,997)
Investments in subsidiaries	(681,766)			681,766	
Other		(24,475)	(315)		(24,790)
Net cash used in investing activities	(681,766)	(710,345)	(18,001)	681,766	(728,346)
Cash flows from financing activities:					
Repurchase of common stock	(67,170)				(67,170)
Proceeds from long-term debt, net of issuance costs	1,127,029		243,310		1,370,339
Payments on long-term debt	(1,031,500)		(141,000)		(1,172,500)
Net equity distributions		806,460	(124,694)	(681,766)	
Other	24,668	(15,120)	(74,773)		(65,225)
Net cash provided by (used in) financing activities	53,027	791,340	(97,157)	(681,766)	65,444
Increase (decrease) in cash and cash equivalents	606	(887)	616		335
Cash and cash equivalents, beginning of period	1	1,700	3		1,704
	$ 607	$ 813	$ 619	$	$ 2,039

Cash and cash equivalents, end of period

Table of Contents

ENCORE ACQUISITION COMPANY

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

CONDENSED CONSOLIDATING STATEMENT OF CASH FLOWS
For the Year Ended December 31, 2007

	Parent	Guarantor Subsidiaries	Non-Guarantor Subsidiaries (In thousands)	Eliminations	Consolidated Total
Cash flows from operating activities:					
Net cash provided by (used in) operating activities	$ (305,868)	$ 615,484	$ 10,091	$	$ 319,707
Cash flows from investing activities:					
Proceeds from disposition of assets		287,928			287,928
Acquisition of oil and natural gas properties		(518,251)	(330,294)		(848,545)
Development of oil and natural gas properties		(329,252)	(6,645)		(335,897)
Investments in subsidiaries	(93,658)			93,658	
Other		(32,585)	(457)		(33,042)
Net cash used in investing activities	(93,658)	(592,160)	(337,396)	93,658	(929,556)
Cash flows from financing activities:					
Proceeds from issuance of ENP common units, net of issuance costs			193,461		193,461
Proceeds from long-term debt, net of issuance costs	1,208,501		270,758		1,479,259
Payments on long-term debt	(809,428)		(225,000)		(1,034,428)
Net equity contributions			93,658	(93,658)	
Other	454	(22,387)	(5,569)		(27,502)
Net cash provided by (used in) financing activities	399,527	(22,387)	327,308	(93,658)	610,790
Increase in cash and cash equivalents	1	937	3		941
		763			763

Cash and cash equivalents, beginning of period										
Cash and cash equivalents, end of period	$	1	$	1,700	$	3	$		$	1,704

Note 15. ENP

In September 2007, ENP completed its IPO of 9,000,000 common units at a price to the public of $21.00 per unit. In October 2007, the underwriters exercised in full their over-allotment option to purchase an additional 1,148,400 common units of ENP. The net proceeds of approximately $193.5 million, after deducting the underwriters discount and a structuring fee of approximately $14.9 million, in the aggregate, and offering expenses of approximately $4.7 million, were used to repay in full $126.4 million of outstanding indebtedness under OLLC s subordinated credit agreement with EAP Operating, LLC, and reduce outstanding borrowings under the OLLC Credit Agreement.

Table of Contents

ENCORE ACQUISITION COMPANY

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

In connection with ENP s IPO, EAC, ENP, and certain of their respective subsidiaries entered into a contribution, conveyance and assumption agreement (the Contribution Agreement) and an administrative services agreement (the Administrative Services Agreement), each as more fully described below. In addition, the board of directors of GP LLC adopted the Encore Energy Partners GP LLC Long-Term Incentive Plan (the ENP Plan), as more fully described below.

Contribution, Conveyance and Assumption Agreement

At the closing of ENP s IPO, the following transactions, among others, occurred pursuant to the Contribution Agreement:

Encore Operating contributed certain oil and natural gas properties and related assets in the Permian Basin in West Texas to ENP in exchange for 4,043,478 common units; and

EAC agreed to indemnify ENP for certain environmental liabilities, tax liabilities, and title defects, as well as defects relating to retained assets and liabilities, occurring or existing before the closing.

These transfers and distributions were made in a series of steps outlined in the Contribution Agreement. In connection with the issuance of the common units by ENP in exchange for the Permian Basin assets, ENP s IPO, and the exercise of the underwriters over-allotment option to purchase additional common units, GP LLC exchanged such number of common units for general partner units as was necessary to enable it to maintain its then two percent general partner interest in ENP. GP LLC received the common units through capital contributions from EAC of common units it owned.

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 the 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. 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 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.

ENCORE ACQUISITION COMPANY

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

ENP reimburses EAC for any state income, franchise, or similar tax incurred by EAC resulting from the inclusion of ENP in consolidated tax returns with EAC as required by applicable law. The amount of any such reimbursement is limited to the tax that ENP would have incurred had they not been included in a combined group with EAC.

Sales of Assets to ENP

In August 2009, Encore Operating sold 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) to ENP for approximately $179.6 million in cash, which ENP 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 properties to fund a portion of the purchase price of its acquisitions from EXCO.

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 $25.2 million in cash, which ENP 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, which ENP 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 and the issuance of 6,884,776 ENP common units to Encore Operating. 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. ENP financed the cash portion of the purchase price 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 Offerings of 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 used the net proceeds of approximately $129.2 million, after deducting the underwriters discounts and commissions of $5.4 million, in the aggregate, and offering costs of $0.2 million, to fund a portion of the purchase price of the Rockies and Permian Basin Assets.

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 $40.9 million, after deducting the underwriters discounts and commissions of $1.9 million, in the aggregate, and offering costs of approximately $0.2 million, to fund the acquisition of the Vinegarone Assets and a portion of the purchase price of the Williston Basin Assets.

Table of Contents

ENCORE ACQUISITION COMPANY

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Long-Term Incentive Plan

In September 2007, the board of directors of GP LLC adopted 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.

The total number of common units reserved for issuance pursuant to the ENP Plan is 1,150,000. As of December 31, 2009, there were 1,075,000 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 also receive distribution equivalent rights prior to vesting, which entitle them to receive cash equal to the amount of any cash distributions paid by ENP with respect to a common unit during the period the right is outstanding. During 2009, 2008 and 2007, ENP recognized non-cash equity-based compensation expense for the phantom units of approximately $0.4 million, $0.3 million, and $31,000, respectively, 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 2009:

	Number of Shares	Weighted Average Grant Date Fair Value
Outstanding at January 1, 2009	43,750	$ 18.67
Granted	25,000	18.13
Vested	(12,500)	18.83
Forfeited		
Outstanding at December 31, 2009	56,250	18.40

During 2009, 2008, and 2007, ENP issued 25,000, 30,000, and 20,000, respectively, phantom units to members of GP LLC s board of directors, the vesting of which is dependent only on the passage of time and continuation as a board member. The following table provides information regarding ENP s outstanding phantom units at December 31, 2009:

	Year of Vesting				
Year of Grant	**2010**	**2011**	**2012**	**2013**	**Total**
2007	5,000	5,000			10,000
2008	7,500	7,500	6,250		21,250
2009	6,250	6,250	6,250	6,250	25,000
Total	18,750	18,750	12,500	6,250	56,250

As of December 31, 2009, ENP had $0.7 million of total unrecognized compensation cost related to unvested phantom units, which is expected to be recognized over a weighted average period of 2.2 years.

ENCORE ACQUISITION COMPANY

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

During 2009 and 2008, there were 12,500 and 6,250, respectively, phantom units that vested, the total fair value of which was $0.2 million and $0.1 million, respectively.

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.

The fair value of the management incentive units was estimated on the date of grant using a discounted dividend model. During 2008 and 2007, ENP recognized total non-cash equity-based compensation expense for the management incentive units of $4.8 million and $6.8 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 2009, 2008, and 2007, ENP paid cash distributions of approximately $81.7 million, $74.4 million, and $1.3 million, respectively, of which $43.9 million, $46.9 million, and $0.8 million, respectively, was paid to EAC and had no impact on EAC s consolidated cash.

During 2008 and 2007, ENP paid cash distributions of approximately $3.5 million and $29,000, 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 16. Segment Information

The following tables provide EAC s operating segment information required by ASC 280-10 (formerly SFAS No. 131, *Disclosure about Segments of an Enterprise and Related Information*) as well as the results of operations from oil and natural gas producing activities required by ASC 932-235 (formerly SFAS No. 69, *Disclosures about Oil and Gas Producing Activities*.

ENCORE ACQUISITION COMPANY

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

	For the Year Ended December 31, 2009			
	EAC Standalone	ENP	Eliminations	Consolidated Total
	(In thousands)			
Revenues:				
Oil	$ 421,780	$ 127,611	$	$ 549,391
Natural gas	108,757	22,428		131,185
Marketing	4,362	478		4,840
Total revenues	534,899	150,517		685,416
Expenses:				
Production:				
Lease operating	123,386	41,676		165,062
Production, ad valorem, and severance taxes	53,440	16,099		69,539
Depletion, depreciation, and amortization	234,019	56,757		290,776
Impairment of long-lived assets	9,979			9,979
Exploration	49,356	3,132		52,488
General and administrative	48,219	11,375	(5,570)	54,024
Marketing	3,692	302		3,994
Derivative fair value loss	12,133	47,464		59,597
Other operating	30,348	3,099		33,447
Total expenses	564,572	179,904	(5,570)	738,906
Operating income (loss)	(29,673)	(29,387)	5,570	(53,490)
Other income (expenses):				
Interest	(68,043)	(10,974)		(79,017)
Other	7,971	46	(5,570)	2,447
Total other expenses	(60,072)	(10,928)	(5,570)	(76,570)
Income (loss) before income taxes	(89,745)	(40,315)		(130,060)
Income tax benefit (provision)	32,187	(14)		32,173
Consolidated net loss	(57,558)	(40,329)		(97,887)
Change in deferred hedge loss on interest rate swaps, net of tax	(339)	839		500
Consolidated comprehensive loss	$ (57,897)	$ (39,490)	$	$ (97,387)

Costs incurred related to oil and natural gas properties	$ 665,800	$ 40,686	$	$ 706,486

Table of Contents

ENCORE ACQUISITION COMPANY

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

	For the Year Ended December 31, 2008			
	EAC Standalone	ENP	Eliminations	Consolidated Total
	(In thousands)			
Revenues:				
Oil	$ 670,830	$ 226,613	$	$ 897,443
Natural gas	173,535	53,944		227,479
Marketing	5,172	5,324		10,496
Total revenues	849,537	285,881		1,135,418
Expenses:				
Production:				
Lease operating	130,363	44,752		175,115
Production, ad valorem, and severance taxes	82,497	28,147		110,644
Depletion, depreciation, and amortization	170,715	57,537		228,252
Impairment of long-lived assets	59,526			59,526
Exploration	39,011	196		39,207
General and administrative	36,082	16,605	(4,266)	48,421
Marketing	4,104	5,466		9,570
Derivative fair value gain	(249,356)	(96,880)		(346,236)
Other operating	13,289	1,670		14,959
Total expenses	286,231	57,493	(4,266)	339,458
Operating income	563,306	228,388	4,266	795,960
Other income (expenses):				
Interest	(66,204)	(6,969)		(73,173)
Other	8,065	99	(4,266)	3,898
Total other expenses	(58,139)	(6,870)	(4,266)	(69,275)
Income before income taxes	505,167	221,518		726,685
Income tax provision	(240,859)	(762)		(241,621)
Consolidated net income	264,308	220,756		485,064
Amortization of deferred loss on commodity derivative contracts, net of tax	1,786			1,786
Change in deferred hedge loss on interest rate swaps, net of tax	941	(4,258)		(3,317)

Consolidated comprehensive income	$ 267,035	$ 216,498	$	$ 483,533
Costs incurred related to oil and natural gas properties	$ 730,908	$ 45,613	$	$ 776,521

Table of Contents

ENCORE ACQUISITION COMPANY

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

	For the Year Ended December 31, 2007			
	EAC Standalone	ENP	Eliminations	Consolidated Total
	(In thousands)			
Revenues:				
Oil	$ 427,271	$ 135,546	$	$ 562,817
Natural gas	110,988	39,119		150,107
Marketing	33,439	8,582		42,021
Total revenues	571,698	183,247		754,945
Expenses:				
Production:				
Lease operating	109,446	33,980		143,426
Production, ad valorem, and severance taxes	56,873	17,712		74,585
Depletion, depreciation, and amortization	136,486	47,494		183,980
Exploration	27,600	126		27,726
General and administrative	25,923	15,245	(2,044)	39,124
Marketing	33,876	6,673		40,549
Derivative fair value loss	86,182	26,301		112,483
Other operating	21,456	1,426		22,882
Total expenses	497,842	148,957	(2,044)	644,755
Operating income	73,856	34,290	2,044	110,190
Other income (expenses):				
Interest	(82,417)	(12,702)	6,415	(88,704)
Other	10,930	196	(8,459)	2,667
Total other expenses	(71,487)	(12,506)	(2,044)	(86,037)
Income before income taxes	2,369	21,784		24,153
Income tax provision	(14,398)	(78)		(14,476)
Consolidated net income (loss)	(12,029)	21,706		9,677
Amortization of deferred loss on commodity derivative contracts, net of tax	33,541			33,541
Consolidated comprehensive income	$ 21,512	$ 21,706	$	$ 43,218
	$ 686,720	$ 529,439	$	$ 1,216,159

Costs incurred related to oil and natural gas properties

Table of Contents

ENCORE ACQUISITION COMPANY

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

	December 31, 2009	December 31, 2008
	(In thousands)	
Segment assets:		
EAC Standalone	$ 2,952,523	$ 2,823,778
ENP	719,651	813,313
Eliminations	(8,213)	(3,896)
Total consolidated assets	$ 3,663,961	$ 3,633,195
Segment liabilities:		
EAC Standalone	$ 1,722,261	$ 1,961,453
ENP	313,647	193,962
Eliminations	(2,780)	(5,468)
Total consolidated liabilities	$ 2,033,128	$ 2,149,947

Note 17. Impairment of Long-Lived Assets

During 2009 and 2008, circumstances indicated that the carrying value of certain of EAC s oil and natural gas properties in the Tuscaloosa Marine Shale may not be recoverable. For the proved oil and natural gas property costs, EAC compared the assets carrying value to the undiscounted expected future net cash flows, which indicated the need for an impairment charge. EAC then compared the net book value of the impaired assets to their estimated discounted value, which resulted in a pretax write-down of the value of oil and natural gas properties. For the unproved acreage costs, EAC recorded a valuation allowance to reflect the portion of the property costs that it believes will not be transferred to proved properties over the remaining life of the lease. The impairment of proved oil and natural gas properties and unproved acreage in the Tuscaloosa Marine Shale totaled $10.0 million and $59.5 million, during 2009 and 2008, respectively. Fair value was determined using estimates of future production volumes and estimates of future prices EAC might receive for these volumes, discounted to a present value. EAC s estimates of undiscounted cash flows indicated that the remaining carrying amounts of its oil and natural gas properties are expected to be recovered. Nonetheless, if oil and natural gas prices decline, it is reasonably possible that EAC s estimates of undiscounted cash flows may change in the near term resulting in the need to record an additional write down of oil and natural gas properties to fair value.

As of December 31, 2009, EAC does not have any unproved oil and natural gas properties in the Tuscaloosa Marine Shale whose carrying value has not been written down to zero.

Note 18. Subsequent Events

Subsequent events were evaluated through February 24, 2010, which is the date the financial statements were issued.

Subsequent to December 31, 2009, EAC granted 546,086 shares of restricted stock to employees as part of its annual incentive program and 202,365 of previously granted stock options and 334,317 shares of previously granted of restricted stock vested. Subsequent to December 31, 2009, it was determined that the performance measures related to certain awards granted in February 2009 were met and, therefore, vesting now depends only on the passage of time and continued employment.

On January 25, 2010, ENP announced that the board of directors of GP LLC declared an ENP cash distribution for the fourth quarter of 2009 to unitholders of record as of the close of business on February 8, 2010 at a rate of $0.5375 per unit. Approximately $24.6 million was paid to unitholders on February 12, 2010.

Table of Contents

ENCORE ACQUISITION COMPANY

SUPPLEMENTARY INFORMATION

Capitalized Costs and Costs Incurred Relating to Oil and Natural Gas Producing Activities

The capitalized cost of oil and natural gas properties was as follows as of the dates indicated:

	December 31, 2009	December 31, 2008
	(In thousands)	
Properties and equipment, at cost successful efforts method:		
Proved properties, including wells and related equipment	$ 4,204,622	$ 3,538,459
Unproved properties	95,601	124,339
Accumulated depletion, depreciation, and amortization	(1,058,267)	(771,564)
	$ 3,241,956	$ 2,891,234

The following table summarizes costs incurred related to oil and natural gas properties for the periods indicated:

	Year Ended December 31, 2009	2008	2007
	(In thousands)		
Acquisitions:			
Proved properties(a)	$ 402,457	$ 28,840	$ 796,239
Unproved properties	17,087	128,635	52,306
Total acquisitions	419,544	157,475	848,545
Development:			
Drilling and exploitation(b)	121,259	362,609	270,161
Total development	121,259	362,609	270,161
Exploration:			
Drilling and exploitation	163,887	252,104	95,221
Geological and seismic	1,022	2,851	1,456
Delay rentals	774	1,482	776
Total exploration	165,683	256,437	97,453
Total costs incurred	$ 706,486	$ 776,521	$ 1,216,159

(a) Includes asset retirement obligations incurred for acquisition activities of $3.7 million, $0.1 million, and $8.3 million in 2009, 2008, and 2007, respectively.

(b) Includes asset retirement obligations incurred for development activities of $0.3 million, $0.5 million, and $0.1 million during 2009, 2008, and 2007, respectively.

Oil & Natural Gas Producing Activities Unaudited

The estimates of EAC s proved oil and natural gas reserves, which are located entirely within the United States, were prepared in accordance with guidelines established by the SEC. Proved oil and natural gas reserve quantities are derived from estimates prepared by Miller and Lents, Ltd., who are independent petroleum engineers.

Future prices received for production and future production costs may vary, perhaps significantly, from the prices and costs assumed for purposes of these estimates. There can be no assurance that the proved reserves will be developed within the periods assumed or that prices and costs will remain constant. Actual

ENCORE ACQUISITION COMPANY

SUPPLEMENTARY INFORMATION (Continued)

production may not equal the estimated amounts used in the preparation of reserve projections. In accordance with SEC guidelines, 2009 estimates of future net cash flows from EAC s properties and the representative value thereof are made using an unweighted average of the closing oil and natural gas prices for the applicable commodity on the first day of each month in 2009 and are held constant throughout the life of the properties. In accordance with past SEC guidelines, 2008 and 2007 estimates of future net cash flows from EAC s properties and the representative value thereof are made using oil and natural gas prices in effect as of the dates of such estimates and are held constant throughout the life of the properties. Prices used in estimating EAC s future net cash flows were as follows:

	2009	2008	2007
Oil (per Bbl)	$ 61.18	$ 44.60	$ 96.01
Natural gas (per Mcf)	$ 3.83	$ 5.62	$ 7.47

EAC s proved reserve and production quantities from its CCA properties have been reduced by the amounts attributable to the net profits interest. The net profits interest on EAC s CCA properties has also been deducted from future cash inflows in the calculation of Standardized Measure. In addition, net future cash inflows have not been adjusted for commodity derivative contracts outstanding at the end of the year. The future net cash flows are reduced by estimated production and development costs, which are based on year-end economic conditions and held constant throughout the life of the properties, and by the estimated effect of future income taxes. Future income taxes are based on statutory income tax rates in effect at year-end, EAC s tax basis in its proved oil and natural gas properties, and the effect of NOL carryforwards and AMT credits.

There are numerous uncertainties inherent in estimating quantities of proved reserves and in projecting future rates of production and timing of development expenditures. Oil and natural gas reserve engineering is and must be recognized as a subjective process of estimating underground accumulations of oil and natural gas that cannot be measured in any exact way, and estimates of other engineers might differ materially from those included herein. The accuracy of any reserve estimate is a function of the quality of available data and engineering, and estimates may justify revisions based on the results of drilling, testing, and production activities. Accordingly, reserve estimates are often materially different from the quantities of oil and natural gas that are ultimately recovered. Reserve estimates are integral to management s analysis of impairments of oil and natural gas properties and the calculation of DD&A on these properties.

EAC s estimated net quantities of proved oil and natural gas reserves were as follows as of the dates indicated:

	December 31,		
	2009	2008	2007
Proved developed reserves:			
Oil (MBbl)	121,401	110,014	125,213
Natural gas (MMcf)	322,422	232,715	191,072
Combined (MBOE)	175,138	148,800	157,058
Proved undeveloped reserves:			

Oil (MBbl)	25,693	24,438	63,374
Natural gas (MMcf)	116,650	74,805	65,375
Combined (MBOE)	45,135	36,905	74,270
Proved reserves:			
Oil (MBbl)	147,094	134,452	188,587
Natural gas (MMcf)	439,072	307,520	256,447
Combined (MBOE)	220,273	185,705	231,328

ENCORE ACQUISITION COMPANY

SUPPLEMENTARY INFORMATION (Continued)

The changes in EAC s proved reserves were as follows for the periods indicated:

	Oil (MBbl)	Natural Gas (MMcf)	Oil Equivalent (MBOE)
Balance, December 31, 2006	153,434	306,764	204,561
Purchases of minerals-in-place	40,534	15,667	43,146
Sales of minerals-in-place	(1,845)	(107,249)	(19,719)
Extensions and discoveries	4,362	65,639	15,302
Improved recovery	666	90	681
Revisions of previous estimates	981	(501)	896
Production	(9,545)	(23,963)	(13,539)
Balance, December 31, 2007	188,587	256,447	231,328
Purchases of minerals-in-place	266	6,220	1,303
Extensions and discoveries	7,411	73,527	19,665
Improved recovery	287		287
Revisions of previous estimates	(52,049)	(2,300)	(52,432)
Production	(10,050)	(26,374)	(14,446)
Balance, December 31, 2008	134,452	307,520	185,705
Purchases of minerals-in-place	6,142	107,614	24,078
Sales of minerals-in-place	(107)	(64)	(117)
Extensions and discoveries	6,902	87,605	21,502
Revisions of previous estimates	9,721	(29,684)	4,774
Production	(10,016)	(33,919)	(15,669)
Balance, December 31, 2009(a)	147,094	439,072	220,273

(a) Includes proved reserves of 28.9 MMBbls of oil and 84.7 Bcf of natural gas (43.0 MMBOE) attributable to ENP in which there was a 53.2 percent noncontrolling interest as of December 31, 2009.

Recent SEC Rule-Making Activity. In December 2008, the SEC announced that it had approved revisions designed to modernize the oil and gas company reserves reporting requirements. Application of the new reserve rules resulted in the use of lower prices at December 31, 2009 for both oil and natural gas than would have resulted under the previous rules. Use of new 12-month average pricing rules at December 31, 2009 resulted in a decrease in proved reserves of approximately 8.5 MMBOE while the change in definition of proved undeveloped reserves increased total proved reserves by 5.7 MMBOE. Therefore, the total impact of the new reserve rules resulted in negative reserves revisions of 2.8 MMBOE. Pursuant to the SEC s final rule, prior period reserves were not restated.

Table of Contents

ENCORE ACQUISITION COMPANY

SUPPLEMENTARY INFORMATION (Continued)

EAC s standardized measure of discounted estimated future net cash flows was as follows as of the dates indicated:

	December 31, 2009	2008 (In thousands)	2007
Future cash inflows	$ 9,416,040	$ 6,754,431	$ 17,394,468
Future production costs	(3,960,587)	(3,082,814)	(5,721,804)
Future development costs	(644,323)	(497,197)	(469,034)
Future abandonment costs, net of salvage	(104,394)	(96,480)	(75,172)
Future income tax expense	(1,089,618)	(555,370)	(3,236,356)
Future net cash flows	3,617,118	2,522,570	7,892,102
10% annual discount	(1,890,048)	(1,302,616)	(4,600,393)
Standardized measure of discounted estimated future net cash flows(a)	$ 1,727,070	$ 1,219,954	$ 3,291,709

(a) Includes $494.5 million attributable to ENP in which there was a 53.2 percent noncontrolling interest as of December 31, 2009.

The changes in EAC s standardized measure of discounted estimated future net cash flows were as follows for the periods indicated:

	Year Ended December 31, 2009	2008 (In thousands)	2007
Net change in prices and production costs	$ 539,118	$ (2,848,387)	$ 1,718,818
Purchases of minerals-in-place	191,573	14,155	1,249,008
Sales of minerals-in-place	448		(300,727)
Extensions, discoveries, and improved recovery	113,043	171,509	282,163
Revisions of previous quantity estimates	133,485	(474,926)	21,887
Production, net of production costs	(433,874)	(321,935)	(710,134)
Previously estimated development costs incurred during the period	120,959	148,569	270,016
Accretion of discount	121,995	329,171	146,181
Change in estimated future development costs	(44,806)	(176,732)	(235,005)
Net change in income taxes	(223,560)	991,368	(672,807)

Change in timing and other	(11,265)	95,453	60,502
Net change in standardized measure	507,116	(2,071,755)	1,829,902
Standardized measure, beginning of year	1,219,954	3,291,709	1,461,807
Standardized measure, end of year	$ 1,727,070	$ 1,219,954	$ 3,291,709

Table of Contents

ENCORE ACQUISITION COMPANY

SUPPLEMENTARY INFORMATION (Continued)

Selected Quarterly Financial Data Unaudited

The following table provides selected quarterly financial data for the periods indicated:

	Quarter			
	First	Second	Third	Fourth
	(In thousands, except per share data)			
2009				
Revenues	$ 114,349	$ 163,478	$ 186,004	$ 221,585
Operating income (loss)	$ 4,621	$ (74,609)	$ 30,733	$ (14,235)
Net loss attributable to EAC stockholders	$ (7,556)	$ (46,975)	$ (4,999)	$ (21,605)
Net loss per common share:				
Basic	$ (0.15)	$ (0.91)	$ (0.10)	$ (0.40)
Diluted	$ (0.15)	$ (0.91)	$ (0.10)	$ (0.40)
2008				
Revenues	$ 272,902	$ 357,334	$ 337,478	$ 167,704
Operating income (loss)	$ 68,956	$ (55,925)	$ 375,148	$ 407,781
Net income (loss) attributable to EAC stockholders	$ 31,220	$ (35,720)	$ 206,307	$ 229,005
Net income (loss) per common share:				
Basic	$ 0.58	$ (0.68)	$ 3.88	$ 4.35
Diluted	$ 0.58	$ (0.68)	$ 3.77	$ 4.32

As discussed in Note 2. Summary of Significant Accounting Policies and Note 10. Earnings Per Share, EAC adopted ASC 260-10 on January 1, 2009 and all periods have been restated to calculate earnings per share in accordance therewith.

Table of Contents

ENCORE ACQUISITION COMPANY

ITEM 9. ***CHANGES IN AND DISAGREEMENTS WITH ACCOUNTANTS ON ACCOUNTING AND FINANCIAL DISCLOSURE***

None.

ITEM 9A. ***CONTROLS AND PROCEDURES***

Evaluation of Disclosure Controls and Procedures

In accordance with Exchange Act Rules 13a-15 and 15d-15, we carried out an evaluation, under the supervision and with the participation of management, including our Chief Executive Officer and Chief Financial Officer, of the effectiveness of 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 December 31, 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.

Management s Report on Internal Control Over Financial Reporting

Management is responsible for establishing and maintaining adequate internal control over financial reporting. Our internal control over financial reporting is a process designed under the supervision of our Chief Executive Officer and Chief Financial Officer to provide reasonable assurance regarding the reliability of financial reporting and the preparation of our financial statements for external purposes in accordance with GAAP.

As of December 31, 2009, management assessed the effectiveness of our internal control over financial reporting based on the criteria for effective internal control over financial reporting established in Internal Control Integrated Framework, issued by the Committee of Sponsoring Organizations of the Treadway Commission. Based on that assessment, management determined that we maintained effective internal control over financial reporting as of December 31, 2009, based on those criteria.

Ernst & Young LLP, the independent registered public accounting firm that audited our consolidated financial statements included in this Report, has issued an attestation report on the effectiveness of our internal control over financial reporting as of December 31, 2009. The report, which expresses an unqualified opinion on the effectiveness of our internal control over financial reporting as of December 31, 2009, is included below.

Table of Contents

ENCORE ACQUISITION COMPANY

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

The Board of Directors and Stockholders of
Encore Acquisition Company:

We have audited Encore Acquisition Company s (the Company) internal control over financial reporting as of December 31, 2009, based on criteria established in Internal Control Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (the COSO criteria). Encore Acquisition Company s management is responsible for maintaining effective internal control over financial reporting, and for its assessment of the effectiveness of internal control over financial reporting included in the accompanying Management s Report on Internal Control Over Financial Reporting. Our responsibility is to express an opinion on the Company s internal control over financial reporting based on our audit.

We conducted our audit in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether effective internal control over financial reporting was maintained in all material respects. Our audit included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, testing and evaluating the design and operating effectiveness of internal control based on the assessed risk, and performing such other procedures as we considered necessary in the circumstances. We believe that our audit provides a reasonable basis for our opinion.

A company s internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company s internal control over financial reporting includes those policies and procedures that (1) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (2) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (3) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company s assets that could have a material effect on the financial statements.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

In our opinion, Encore Acquisition Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2009, based on the COSO criteria.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the consolidated balance sheets of Encore Acquisition Company as of December 31, 2009 and 2008, and the related consolidated statements of operations, equity and comprehensive income (loss), and cash flows for each of the three years in the period ended December 31, 2009 and our report dated February 24, 2010 expressed an unqualified opinion thereon.

/s/ Ernst & Young LLP

Fort Worth, Texas
February 24, 2010

ENCORE ACQUISITION COMPANY

Changes in Internal Control over Financial Reporting

There were no changes in our internal control over financial reporting during the fourth quarter of 2009 that materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

ITEM 9B. ***OTHER INFORMATION***

None.

PART III

ITEM 10. ***DIRECTORS, EXECUTIVE OFFICERS AND CORPORATE GOVERNANCE***

Directors and Executive Officers

The following table sets forth certain information regarding the members of the board of directors and the executive officers of EAC. Directors are elected for one-year terms by EAC s stockholders. The directors hold office until the earlier of their death, resignation, removal, or disqualification or until their successors have been elected and qualified. Officers serve at the discretion of the board of directors of EAC.

Name	Age	Position with EAC
I. Jon Brumley	70	Chairman of the Board
Jon S. Brumley	39	Chief Executive Officer, President, and Director
Robert C. Reeves	40	Senior Vice President, Chief Financial Officer, Treasurer, and Corporate Secretary
L. Ben Nivens	49	Senior Vice President and Chief Operating Officer
John W. Arms	42	Senior Vice President, Acquisitions
Kevin Treadway	44	Senior Vice President, Land
Andrea Hunter	35	Vice President, Controller, and Principal Accounting Officer
Thomas H. Olle	55	Vice President, Strategic Solutions
Andy R. Lowe	58	Vice President, Marketing
John A. Bailey	39	Director
Martin C. Bowen	66	Director
Ted Collins, Jr.	71	Director
Ted A. Gardner	52	Director
John V. Genova	55	Director
James A. Winne III	58	Director

Executive Officers

I. Jon Brumley has been Chairman of the Board of EAC since its inception in April 1998. Mr. Brumley has been Chairman of the Board of Encore Energy Partners GP LLC, the general partner of Encore Energy Partners LP, since February 2007. He also served as Chief Executive Officer of EAC from its inception until December 2005 and President of EAC from its inception until August 2002. Beginning in August 1996, Mr. Brumley served as Chairman and Chief Executive Officer of MESA Petroleum (an independent oil and gas company) until MESA s merger in August 1997 with Parker & Parsley to form Pioneer Natural Resources Company (an independent oil and gas company). He served as Chairman and Chief Executive Officer of Pioneer until joining EAC in 1998. Mr. Brumley received a Bachelor of Business Administration from the University of Texas and a Master of Business Administration from the University of Pennsylvania Wharton School of Business. He is the father of Jon S. Brumley.

Jon S. Brumley has been the Chief Executive Officer EAC since January 2006, President of EAC since August 2002, and a director of EAC since November 2001. Mr. Brumley has been the Chief Executive Officer,

ENCORE ACQUISITION COMPANY

President, and director of Encore Energy Partners GP LLC since February 2007. He also held the positions of Executive Vice President Business Development and Corporate Secretary from EAC s inception in April 1998 until August 2002 and was a director of EAC from April 1999 until May 2001. Prior to joining EAC, Mr. Brumley held the position of Manager of Commodity Risk and Commercial Projects for Pioneer Natural Resources Company. He was with Pioneer since its creation by the merger of MESA and Parker & Parsley in August 1997. Prior to August 1997, Mr. Brumley served as Director Business Development for MESA. Mr. Brumley received a Bachelor of Business Administration in Marketing from the University of Texas. He is the son of I. Jon Brumley.

Robert C. Reeves has been the Senior Vice President, Chief Financial Officer, and Treasurer of EAC since November 2006 and Corporate Secretary of EAC since May 2008. Mr. Reeves has been the Senior Vice President, Chief Financial Officer, and Treasurer of Encore Energy Partners GP LLC since February 2007 and Corporate Secretary since May 2008. From November 2006 until January 2007, Mr. Reeves also served as Corporate Secretary of EAC. Mr. Reeves served as Senior Vice President, Chief Accounting Officer, Controller, and Assistant Corporate Secretary of EAC from November 2005 until November 2006. He served as EAC s Vice President, Controller, and Assistant Corporate Secretary from August 2000 until October 2005. He served as Assistant Controller of EAC from April 1999 until August 2000. Prior to joining EAC, Mr. Reeves served as Assistant Controller for Hugoton Energy Corporation. Mr. Reeves received his Bachelor of Science degree in Accounting from the University of Kansas. He is a Certified Public Accountant.

L. Ben Nivens has been the Senior Vice President and Chief Operating Officer of EAC since November 2006. Mr. Nivens has been the Senior Vice President and Chief Operating Officer of Encore Energy Partners GP LLC since February 2007. From October 2005 until November 2006, Mr. Nivens served as Senior Vice President, Chief Financial Officer, Treasurer, and Corporate Secretary of EAC. Mr. Nivens served as EAC s Vice President of Corporate Strategy and Treasurer from June 2005 until October 2005. From April 2002 to June 2005, Mr. Nivens served as engineering manager and in other engineering positions for EAC. Prior to joining EAC, he worked as a reservoir engineer for Prize Energy from 1999 to 2002. From 1990 to 1999, Mr. Nivens worked in the corporate planning group at Union Pacific Resources and also served as a reservoir engineer. In addition, he worked as a reservoir engineer for Compass Bank in 1999. Mr. Nivens received a Bachelor of Science in Petroleum Engineering from Texas Tech University and a Masters of Business Administration from Southern Methodist University.

John W. Arms has been the Senior Vice President Acquisitions of EAC and Encore Energy Partners GP LLC since February 2007. Mr. Arms served as Vice President of Business Development of EAC from September 2001 until February 2007. From November 1998 until September 2001, Mr. Arms served as Manager of Acquisitions and in various other petroleum engineering positions for EAC. Prior to joining EAC in November 1998, Mr. Arms was a Senior Reservoir Engineer for Union Pacific Resources and an Engineer at XTO Energy, Inc. Mr. Arms received a Bachelor of Science in Petroleum Engineering from the Colorado School of Mines.

Kevin Treadway has been the Senior Vice President Land of EAC and Encore Energy Partners GP LLC since February 2008. Mr. Treadway served as the Vice President Land of EAC from April 2003 to February 2008. Mr. Treadway served as the Vice President Land of Encore Energy Partners GP LLC from February 2007 to February 2008. From May 2000 to April 2003, Mr. Treadway held various positions of increasing responsibility in EAC s land department. Prior to joining EAC in May 2000, Mr. Treadway served as a landman at Coho Resources. Mr. Treadway received a Bachelor of Science in Petroleum Land Management from the University of Southwestern Louisiana.

Andrea Hunter has been the Vice President, Controller, and Principal Accounting Officer of EAC and Encore Energy Partners GP LLC since February 2008. From September 2007 to February 2008, Ms. Hunter served as Controller of our general partner and EAC since September 2007. From July 2003 to September 2007, Ms. Hunter held positions of increasing responsibility at EAC, including financial reporting senior manager. Prior to joining EAC in July 2003, Ms. Hunter worked in public accounting, first in the Assurance

Table of Contents

ENCORE ACQUISITION COMPANY

and Business Advisory Services of PricewaterhouseCoopers LLP and later as an editor at Thomson Publishing s Practitioners Publishing Company. Ms. Hunter received a Master of Science and Bachelor of Business Administration, both in Accounting, from the University of Texas at Arlington. She is a Certified Public Accountant.

Thomas H. Olle has been the Vice President, Strategic Solutions of EAC and Encore Energy Partners GP LLC since February 2008. From November 2006 to February 2008, Mr. Olle served as Vice President, Mid-Continent Region of EAC. From February 2007 to February 2008, Mr. Olle served as Vice President, Mid-Continent Region of Encore Energy Partners GP LLC. From February 2005 until November 2006, Mr. Olle was EAC s Senior Vice President, Asset Management. Mr. Olle served as EAC s Senior Vice President, Asset Management of the Cedar Creek Anticline from April 2003 to February 2005. Mr. Olle joined EAC in March 2002 as Vice President of Engineering. Prior to joining EAC, Mr. Olle served as Senior Engineering Advisor of Burlington Resources, Inc. (an independent oil and gas company) from September 1999 to March 2002. From July 1986 to September 1999, he served as Regional Engineer of Burlington Resources. Mr. Olle received a Bachelor of Science degree with Highest Honors in Mechanical Engineering from the University of Texas at Austin.

Andy R. Lowe has been the Vice President, Marketing of EAC since February 2007. Mr. Lowe has been the Vice President, Marketing of Encore Energy Partners GP LLC since February 2008. From May 2006 until February 2007, Mr. Lowe was EAC s Director of Marketing. Prior to joining EAC, Mr. Lowe was Vice President Marketing for Vintage Petroleum, Inc. from December 1997 until December 2005. Mr. Lowe served as General Manager Marketing for Vintage Petroleum, Inc. from 1992 until December 1997. Mr. Lowe served as president of Quasar Energy, Inc. from 1990 until 1992, providing downstream natural gas marketing services. From September 1983 to November 1990, he was employed by Maxus Energy Corporation, formerly Diamond Shamrock Exploration Company, serving as Manager of Marketing and in various other management and supervisory capacities. From 1981 to September 1983, he was employed by American Quasar Exploration Company as Manager of Oil and Gas Marketing. From 1978 to 1981, Mr. Lowe was employed by Texas Pacific Oil Company serving in various positions in production and marketing. Mr. Lowe received a Bachelor of Science degree in Education from Texas Tech University.

Directors

I. Jon Brumley. Please refer to page 146.

Jon S. Brumley. Please refer to page 146.

John A. Bailey has been a director of EAC since May 2006. Mr. Bailey has been the Managing Partner of 1859 Partners LLC, an investment partnership, since March 2009. From August 2008 to March 2009, Mr. Bailey was the Managing Partner of J. Bailey & Co LLC, an industry consultancy, and actively involved in the formation of 1859 Partners LLC. From December 2006 until August 2008, Mr. Bailey was a Portfolio Manager, Global Energy, at Carlyle Blue Wave Partners Management, LP. From March 2005 to October 2006, Mr. Bailey was employed as Vice President, Energy at Amaranth Group LLC and a consultant to Amaranth Group LLC from October 2004 until March 2005. From October 2000 until August 2004, Mr. Bailey was an equity research analyst and Vice President of Equity Research for Deutsche Bank Securities with a focus on the North American exploration and production segment of the energy industry. From May 1997 until May 2000, Mr. Bailey was part of the oil and natural gas equity research group at Donaldson, Lufkin & Jenrette, Inc. Mr. Bailey received a Bachelor of Arts degree in Economics and Government from Cornell University. Mr. Bailey was a director of Crosspoint Energy Company from July 2006 to October 2007.

Martin C. Bowen has been a director of EAC since May 2004. Since 1993, Mr. Bowen has been Vice President and Chief Financial Officer of Fine Line, L.P., a private holding company. He also serves on the Board of Directors of AZZ, Inc. and several privately held companies. In addition, he is a Director and Executive Committee Member of the Southwestern Exposition and Livestock Show and Vice President and Treasurer of Performing Arts Fort Worth. Mr. Bowen received a Bachelor of Business Administration in

ENCORE ACQUISITION COMPANY

Finance from Texas A&M University, a Bachelor of Foreign Trade from the American Graduate School of International Management, and a Juris Doctor from Baylor University School of Law.

Ted Collins, Jr. has been a director of EAC since May 2001. From 1988 to July 2000, he was a co-founder and president of Collins & Ware, Inc. (an independent oil and natural gas exploration company which was sold in July 2000). Since that time he has engaged in private oil and natural gas investments. Mr. Collins is a past President of the Permian Basin Petroleum Association, the Permian Basin Landmen s Association and the Midland Petroleum Club. He currently serves as Chairman of the Midland Wildcat Committee. He is a graduate of the University of Oklahoma with a Bachelor of Science in Geological Engineering. Mr. Collins serves on the Board of Directors of the general partner of Energy Transfer Partners, L.P. Mr. Collins was a director of Hanover Compressor Company from April 1992 to August 2007.

Ted A. Gardner has been a director of EAC since May 2001. Mr. Gardner has been Managing Partner of Silverhawk Capital Partners (a private equity investment group) since June 2005. From June 2003 to June 2005, Mr. Gardner was an independent investor. Mr. Gardner was a Managing Partner of Wachovia Capital Partners (a private equity investment group) and a Senior Vice President of Wachovia Corporation (a provider of commercial and retail banking and trust services) from 1990 until 2003. Mr. Gardner was a director of Kinder Morgan, Inc. from October 1999 to May 2007 and a director of COMSYS IT Partners Inc. from September 2004 to July 2006. Mr. Gardner received a Bachelor of Arts degree in Economics from Duke University and a Juris Doctor and Masters of Business Administration from the University of Virginia.

John V. Genova has been a director of EAC since May 2004. Mr. Genova has been President, Chief Executive Officer, and a director of Sterling Chemicals since May 2008. In September 2009, Mr. Genova joined the Advisory Board of 1859 Partners LLC. From March 2006 to May 2008, Mr. Genova was Vice President of Corporate Planning for Tesoro Corporation (an independent petroleum refiner). From July 2005 to March 2006, Mr. Genova was Vice President of Performance Management for Tesoro Corporation. He also served as an energy advisor for the Gerson Lehrman Group from 2004 to May 2008 and as a Senior Energy Advisor to Chanin Capital Partners from early 2005 to May 2008. From January 2005 to July 2005, Mr. Genova was an independent consultant to the energy industry. Previously, Mr. Genova was Executive Vice President Refining and Marketing of Holly Corporation (an independent U.S. petroleum refiner) from January 2004 to December 2004. Prior to Holly, Mr. Genova worked over 27 years with ExxonMobil. From January 1999 to December 1999, he served as Vice President of the Gas Department of Exxon Company, International. From December 1999 to March 2002, he served as Director of International Gas Marketing of ExxonMobil International Limited in London. From April 2002 through 2003, Mr. Genova served as Executive Assistant to the Chairman and General Manager, Corporate Planning of ExxonMobil Corporation. Mr. Genova received a Bachelor of Science degree in Chemical and Petroleum Refining Engineering from the Colorado School of Mines.

James A. Winne III has been a director of EAC since August 2008 and was a director of EAC from May 2001 until July 2008. He is President and Chief Executive Officer of Legend Natural Gas II, L.P. (an independent oil and natural gas company) since September 2004, President and Chief Executive Officer of Legend Natural Gas III, L.P. (an independent oil and natural gas company) since August 2006, President and Chief Executive Officer of Legend Natural Gas IV, L.P. (an independent oil and natural gas company) since 2009, and President and Chief Executive Officer of Legend Natural Gas L.L.C. (an independent oil and natural gas company) since 2009. Mr. Winne is also non-executive Chairman of the Board of Phoenix Exploration Company, a privately held oil and natural gas exploration company. Mr. Winne was President and Chief Executive Officer of Legend Natural Gas, L.P. (an independent oil and natural gas company) from September 2001 until August 2004. Mr. Winne was a director of

Belden & Blake Corporation (an independent oil and natural gas company) from September 2004 until August 2005 and served as Chairman of the Board and Chief Executive Officer of Belden & Blake from December 2004 until August 2005. From March 2001 until September 2001, Mr. Winne developed plans for a business that became Legend Natural Gas. He was formerly employed by North Central Oil Corporation (an independent oil and natural gas company) for 18 years and was President and Chief Executive Officer from September 1993 until March 2001. After attending the

Table of Contents

ENCORE ACQUISITION COMPANY

University of Houston, he started his career as an independent landman and also worked at Tomlinson Interest, Inc. (an independent oil and natural gas company) and Longhorn Oil and Gas (an independent oil and natural gas company) before joining North Central s land department in January 1983. Mr. Winne is a land professional with 30 years of experience in the oil and gas industry.

Director Independence

The Board has determined that each director is independent, as defined for purposes of the listing standards of the NYSE, other than Mr. I. Jon Brumley, who is our Chairman of the Board, and Mr. Jon S. Brumley, who is our Chief Executive Officer and President. In making this determination, the Board affirmatively determined that each independent director had no material relationship with EAC (either directly or indirectly as a partner, stockholder, or officer of an organization that has a relationship with EAC), and that none of the express disqualifications contained in the NYSE rules applied to any of them.

The Board has adopted categorical standards to assist it in making independence determinations. However, the Board considers all material relationships with each director in making its independence determinations. A relationship falls within the categorical standards if it:

Is a type of relationship addressed in Item 404 of Regulation S-K under the Exchange Act or Section 303A.02(b) of the NYSE Listed Company Manual, but those rules neither require disclosure nor preclude a determination of independence; or

Consists of charitable contributions by EAC to an organization where a director is an executive officer and does not exceed the greater of $1 million or 2 percent of the organization s gross revenue in any of the last three years.

None of the independent directors had relationships relevant to an independence determination that were outside the scope of the categorical standards.

Board Committees

As of February 17, 2010, the Board had the following committees: (1) Audit; (2) Compensation; (3) Nominating and Corporate Governance; and (4) Special Stock Award. The following table sets forth the membership on each committee:

Name	Audit	Compensation	Nominating and Corporate Governance	Special Stock Award
I. Jon Brumley				
Jon S. Brumley				Member
John A. Bailey	Member			
Martin C. Bowen		Member		

Ted Collins, Jr.		Member	Chair
Ted A. Gardner	Chair		
John V. Genova	Member		
James A. Winne III		Chair	Member

In 2009, the Audit Committee held eight meetings, the Compensation Committee held one meeting, the Nominating and Corporate Governance Committee held one meeting, and the Board held 12 meetings. Each director attended at least 75 percent of all Board and applicable committee meetings in 2009. Directors are encouraged to attend annual stockholder meetings. All of our directors attended the 2009 annual meeting of stockholders.

ENCORE ACQUISITION COMPANY

Audit Committee. The Audit Committee s purpose is, among other things, to assist the Board in overseeing:

the integrity of our financial statements;

our compliance with legal and regulatory requirements;

the independence, qualifications, and performance of our independent registered public accounting firm; and

the performance of our internal audit function.

The Board has determined that all members of the Audit Committee are independent under the listing standards of the NYSE and the rules of the SEC. In addition, the Board has determined that Mr. Gardner is an audit committee financial expert as defined in Item 407(d)(5) of Regulation S-K.

The charter of the Audit Committee is available free of charge on the Corporate Governance section of our website at www.encoreacq.com.

Compensation Committee. The Compensation Committee s functions include the following:

review and approve corporate goals and objectives relevant to Chief Executive Officer compensation, evaluate the Chief Executive Officer s performance in light of those goals and objectives, and, either as a committee or together with the other independent directors (as directed by the Board), determine and approve the Chief Executive Officer s compensation level based on this evaluation;

approve, or make recommendations to the Board with respect to, the compensation of other executive officers;

from time to time consider and take action on the establishment of and changes to incentive compensation plans and equity-based compensation plans, including making recommendations to the Board on plans, goals, or amendments to be submitted for action by our stockholders;

administer our compensation plans that it is assigned responsibility to administer, including taking action on grants and awards, determinations with respect to achievement of performance goals, and other matters provided in the respective plans;

review from time to time when and as it deems appropriate the compensation and benefits of non-employee directors, including compensation pursuant to equity-based plans, and approve, or recommend to the Board for its action, any changes in such compensation and benefits; and

produce a compensation committee report on executive compensation as required by the SEC to be included in our annual proxy statement or annual report on Form 10-K.

The Board has determined that all members of the Compensation Committee are independent under the listing standards of the NYSE.

The compensation payable to our Chairman of the Board and Chief Executive Officer is reviewed and approved by the Compensation Committee in executive session. The compensation payable to our other executive officers is recommended by our Chairman of the Board and Chief Executive Officer and reviewed and approved by the Compensation Committee.

The report of the Compensation Committee is included in this Report on page 160. The charter of the Compensation Committee is available free of charge on the Corporate Governance section of our website at www.encoreacq.com.

ENCORE ACQUISITION COMPANY

Nominating and Corporate Governance Committee. The Nominating and Corporate Governance Committee s functions include the following:

identify individuals qualified to become Board members, consistent with criteria approved by the Board;

recommend to the Board a slate of director nominees to be elected at the next annual meeting of stockholders and, when appropriate, director appointees to take office between annual meetings;

develop and recommend to the Board the corporate governance guidelines applicable to EAC;

oversee the Board s annual evaluation of its performance and that of management; and

recommend to the Board membership on standing Board committees.

The Board has determined that all members of the Nominating and Corporate Governance Committee are independent under the listing standards of the NYSE.

The charter of the Nominating and Corporate Governance Committee is available free of charge on the Corporate Governance section of our website at www.encoreacq.com.

Special Stock Award Committee. The Special Stock Award Committee may exercise all powers and authority of the Board (concurrently with the Compensation Committee) to award restricted shares (or units representing restricted shares) of our common stock, or restricted stock, to eligible employees under our equity-based incentive plan, subject to the following limitations:

the Special Stock Award Committee may not make any award of shares of restricted stock to any officer or director of EAC who is subject to the provisions of Section 16 of the Exchange Act;

the maximum number of shares of restricted stock that may be granted by the Special Stock Award Committee to one or more eligible employees may not exceed, in the aggregate, 25,000 shares in any calendar year (which amount may be increased as to any calendar year by action of the Compensation Committee), and no unused portion of such authorized amount shall be carried forward to another calendar year; and

after the initial grant of any award of shares of restricted stock by the Special Stock Award Committee, such award will then be administered by the Compensation Committee.

Code of Business Conduct and Ethics and Governance Guidelines

We have adopted a Code of Business Conduct and Ethics for our directors, officers (including our principal executive officer, principal financial officer, and principal accounting officer), and employees. We have also adopted Corporate Governance Guidelines, which, in conjunction with our certificate of incorporation, bylaws, and Board committee charters, form the framework for our governance. We will post on our website any amendments to the Code of Business Conduct and Ethics or waivers of the Code of Business Conduct and Ethics for directors and executive officers.

Table of Contents

ENCORE ACQUISITION COMPANY

Our Code of Business Conduct and Ethics and Corporate Governance Guidelines are available free of charge on the Corporate Governance section of our website at www.encoreacq.com.

Executive Sessions of Non-Management Directors

Our non-management directors include all directors other than I. Jon Brumley and Jon S. Brumley. Each of the non-management directors is independent under the listing standards of the NYSE. The non-management directors meet in executive session without management participation at least three times per year. The purpose of these executive sessions is to promote open and candid discussion among the non-management directors. These meetings are chaired on a rotating basis by the chairmen of the Audit Committee, the Compensation Committee, and the Nominating and Corporate Governance Committee.

Stockholder Communications

Individuals may communicate with the entire Board or with our non-management directors. Any such communication should be sent via letter addressed to the member or members of the Board to whom the communication is directed. All such communications, other than unsolicited commercial solicitations or communications, will be forwarded to the appropriate director or directors for review.

Section 16(a) Beneficial Ownership Reporting Compliance

Section 16(a) of the Exchange Act requires our directors, executive officers, and holders of more than 10 percent of our common stock to file reports with the SEC regarding their ownership and changes in ownership of our securities. We believe that, during 2009, our directors, executive officers, and 10 percent stockholders complied with all Section 16(a) filing requirements. In making these statements, we have relied upon examination of the copies of Forms 3 and 4, and amendments thereto, provided to us and the written representations of our directors and executive officers.

ITEM 11. *EXECUTIVE COMPENSATION*

Compensation Discussion and Analysis

This Compensation Discussion and Analysis is intended to provide investors with an understanding of our compensation policies and decisions regarding our named executive officers. Our named executive officers are our Chief Executive Officer, our Chief Financial Officer, and our three other most highly compensated executive officers for 2009.

Proposed Merger with Denbury Resources Inc.

On October 31, 2009, we entered into an agreement and plan of merger with Denbury Resources Inc., or Denbury, pursuant to which we have agreed to merge with and into Denbury. The merger agreement provides for Denbury s acquisition of all of our issued and outstanding shares of common stock in a transaction valued at approximately $4.5 billion, including the assumption of debt and the value of our interest in ENP. We expect to complete the merger during the first quarter of 2010, although completion by any particular date cannot be assured.

The merger consideration of $50.00 per share of EAC common stock (applying the collar mechanism in the merger agreement and based upon the closing sale price of Denbury common stock on October 30, 2009 of $14.60 per share, the last trading date before the date of the EAC board meeting), represented a premium of:

35 percent above the closing sale price of EAC common stock on October 30, 2009 of $37.07 per share;

ENCORE ACQUISITION COMPANY

28 percent above the closing sale price of EAC common stock on October 5, 2009 (the 20th trading day prior to the date of the EAC board meeting) of $39.08 per share; and

11 percent above the highest closing sale price of EAC common stock during the 52-week period ended October 30, 2009 of $44.85 per share.

Under the merger agreement, in general we are allowed to pay our employees the following incentive compensation with respect to calendar year 2009:

a cash bonus with respect to calendar year 2009 in an amount equal to the employee s target annual cash incentive opportunity as determined by the Compensation Committee on February 9, 2009; and

an equity compensation bonus with respect to calendar year 2009 in an amount equal to the employee s target annual equity incentive opportunity, with such equity compensation bonus to be paid solely in the form of restricted shares of EAC common stock, subject to the following terms and conditions:

vesting of the restricted shares will occur over such period of time, but in no event less than four years, and on such terms as the Compensation Committee determines at the time of grant;

the restricted shares will not vest upon the occurrence of the merger with Denbury, but will convert into Denbury common stock based on the exchange ratio set forth in the merger agreement; and

the restricted shares will vest immediately in full upon the termination of the employee s employment by Denbury or an affiliate without cause or due to the employee s resignation for good reason within the meaning of the our Employee Severance Protection Plan.

With respect to calendar year 2010, the target annual incentive opportunity for an employee will be the same as such target for calendar year 2009, and any employee who is terminated following the merger and prior to the date on which annual bonuses for 2010 are paid to Denbury employees in the ordinary course as a result of an involuntary termination without cause or resignation for good reason (within the meaning of our Employee Severance Protection Plan) will receive a bonus payout for 2010 in an amount at least equal to the employee s target annual incentive opportunity (including for this purposes the cash equivalent of any options or restricted stock that would have been payable in respect of performance during calendar year 2010), prorated based on the number of days that have elapsed in calendar year 2010 through the date on which the termination of employment occurs.

Under the merger agreement, we are also permitted to pay additional bonuses to EAC employees (other than the Chief Executive Officer) in an amount not to exceed $1,000,000.

Executive Compensation Philosophy

In establishing executive compensation, we believe that:

base salaries should be at levels competitive with peer group companies that compete with us for business opportunities and executive talent;

annual cash bonuses and equity-based compensation awards should reflect progress toward our corporate, strategic, and operating goals as well as individual performance; and

we should encourage significant executive stock ownership to further align executives interests with those of our stockholders.

ENCORE ACQUISITION COMPANY

Purpose of the Executive Compensation Program

Historically, our executive compensation program has been designed to accomplish the following objectives:

- align executive pay with the creation of stockholder wealth while maintaining good corporate governance;
- produce long-term, positive results for our stockholders;
- align executive compensation with our performance and appropriate peer group companies;
- offer incentives for exceeding performance objectives;
- provide market-competitive compensation and benefits that will enable us to attract, motivate, and retain a talented workforce; and
- prevent short-term inappropriate behavior to manipulate results for the purpose of increasing compensation.

Role of the Compensation Committee

Responsibilities and Authority

The Compensation Committee has overall responsibility for the compensation of our named executive officers. The specific duties and responsibilities of the Compensation Committee are described in Item 10. Directors, Executive Officers and Corporate Governance and in the charter of the Compensation Committee, which is available free of charge on the Corporate Governance section of our website at www.encoreacq.com.

Timing of Decisions

The Compensation Committee generally meets each February to: (1) establish base salaries for the then-current year, (2) approve cash bonuses in respect of corporate and executive performance during the preceding year, (3) award equity-based compensation in respect of corporate and executive performance during the preceding year, and (4) review and, as appropriate, make changes to our executive compensation program. At this meeting, the Compensation Committee establishes the performance goals and objectives for the then-current year. The Compensation Committee also meets at other times during the year and acts by written consent when necessary and appropriate.

The February meeting of the Compensation Committee is typically set at least a year in advance to coincide with the regularly scheduled Board meeting. The timing of Board and committee meetings is determined by our Chairman of the Board in consultation with the other Board and committee members. We do not time the release of material non-public information for the purpose of affecting the values of executive compensation. At the time of making equity-based compensation decisions, the Compensation Committee is aware of the earnings results and takes them into account, but it does not adjust the size of grants to reflect possible market reaction. Generally, grants of equity-based compensation are made at the February meeting of the Compensation Committee, although specific grants may be made at other times to recognize an employee s promotion, change in responsibility, or specific achievement.

Compensation Program

Elements of Compensation

Our executive compensation program consists of the following elements:

- base salary;

ENCORE ACQUISITION COMPANY

annual incentive compensation, which includes an annual cash bonus and long-term incentive compensation; and

perquisites and other benefits.

Base Salaries

We attempt to provide our named executive officers with a base salary that is within range when compared to our peer group. The base salary for each named executive officer reflects his position, responsibilities, and contributions relative to other executives and applicable peer group data provided by an outside consultant. Salaries are typically reviewed each February as part of our performance and compensation review process, as well as at other times to recognize a promotion, change in job responsibilities, or market positioning.

Annual Incentive Compensation

General. In general, an executive s annual incentive compensation consists of the following:

25 percent annual cash bonus;

50 percent restricted stock; and

25 percent stock options.

We believe that making at least 75 percent of an executive s annual incentive compensation contingent on long-term stock price performance more closely aligns the executive s interests with those of our stockholders. Like cash bonuses, stock options and restricted stock awards reflect progress toward our corporate goals and individual performance. However, when the annual cash bonus is not as large, the total amount of annual incentive compensation for executives is decreased because of the multiplier effect relating to equity-based compensation.

The equity component of annual incentive compensation has historically consisted of restricted stock with a value equal to twice the executive s annual cash bonus and stock options with a value equal to the executive s annual cash bonus. However, in the merger agreement with Denbury, we agreed to issue additional shares of restricted stock in lieu of the stock option component of the equity component of annual incentive compensation for 2009.

Annual Cash Bonuses. In February 2009, the Compensation Committee considered a revised compensation program with the intent of creating a production and reserve-driven efficient oil company. The revised program is designed to accomplish the following objectives:

match company and individual performance;

increase shareholder wealth and compensate employees fairly;

increase employee effectiveness by directly linking compensation to defined goals and objectives;

create well-defined, measurable, and attainable objectives for members of the strategic team; and give members of the strategic team more knowledge of their individual goals, their group regional goals, and our corporate objectives.

The revised program builds on our strong entrepreneurial culture by providing employees with clear goals, empowering employees to achieve those goals, and holding employees accountable if the goals are not achieved.

After considering the revised compensation program, the Compensation Committee approved the Strategic Team Bonus Plan (the Bonus Plan) to reward selected executive officers, managers, and certain other key employees for making significant contributions to our success. The following table sets forth the target 2009

Table of Contents

ENCORE ACQUISITION COMPANY

bonus opportunity for our named executive officers (expressed as a percentage of each executive s annual base salary):

Name	Target 2009 Bonus Opportunity
Jon S. Brumley	250%
I. Jon Brumley	200%
L. Ben Nivens	200%
Robert C. Reeves	175%
John W. Arms	125%

Awards under the Bonus Plan are based on the achievement of corporate objectives applicable to all covered employees and strategic and individual objectives tailored to each covered employee. For 2009, the Compensation Committee established the following corporate objectives:

- meet budgeted production volumes;
- achieve negative forecast revisions for proved developed producing properties of one percent or less;
- generate at least $150 million of free cash flow;
- achieve development costs of $22 per Bbl or less; and
- generate a 15 percent rate of return based on constant oil and natural gas prices.

Based on a review of information provided by EAC s management and after considering such other factors that it deemed relevant, the Compensation Committee determined that (1) four of the five corporate objectives had been satisfied with respect to 2009, and (2) each covered employee had met their strategic and individual performance objectives. If one or more of the five corporate objectives had been achieved, the Compensation Committee had discretion to award bonuses under the Bonus Plan based on the achievement of all, a portion of, or none of the other performance objectives.

The actual cash bonus for 2009 was determined based on the following formula: (1) the individual s target 2009 bonus opportunity, multiplied by (2) the level of achievement of corporate, strategic, and individual objectives as determined by the Compensation Committee in its discretion, multiplied by (3) a corporate performance factor (between zero percent and 100 percent) determined by the Compensation Committee in its discretion, multiplied by (4) an individual performance factor (between zero percent and 100 percent) determined by the Compensation Committee in its discretion.

After applying the above factors to the target bonus opportunity and considering such other factors as it deemed appropriate, the Compensation Committee awarded each named executive officer the annual cash bonus for 2009 set forth in the table below, which is compared to the annual cash bonus awarded for 2008:

Increase in 2009

Name	Target 2009 Bonus Opportunity	Total Annual Cash Bonus for 2009	Total Annual Cash Bonus for 2008	Compared to 2008
I. Jon Brumley	$ 772,600	$ 772,600	$ 439,900	$ 332,700
Jon S. Brumley	1,545,000	1,545,000	791,900	753,100
Robert C. Reeves	648,900	648,900	372,700	276,200
L. Ben Nivens	741,600	741,600	369,500	372,100
John W. Arms	418,500	418,500	302,800	115,700

Restricted Stock Awards. The Compensation Committee believes that restricted stock provides a more immediate benefit for purposes of attracting, retaining, and motivating employees in an intensely competitive environment for executive talent. The equity component of annual incentive compensation has historically consisted of restricted stock with a value equal to twice the executive s annual cash bonus and stock options with a value equal to the executive s annual cash bonus. However, in the merger agreement with Denbury, we

ENCORE ACQUISITION COMPANY

agreed to issue additional shares of restricted stock in lieu of the stock option component of the equity component of annual incentive compensation for 2009.

The following table sets forth awards of restricted stock granted on February 8, 2010 with respect to each named executive officer s performance in 2009:

Name	Shares of Restricted Stock		Grant Date Fair Value(a)
I. Jon Brumley	47,564	$	2,317,794
Jon S. Brumley	95,116		4,635,003
Robert C. Reeves	39,949		1,946,715
L. Ben Nivens	45,656		2,224,817
John W. Arms	25,764		1,255,480

(a) Determined by multiplying the number of shares of restricted stock granted to a named executive officer by the strike price, the closing price of our common stock on the NYSE on February 8, 2010, which was the date of grant.

Restricted stock awards granted to our named executive officers (and certain other members of management) with respect to 2009 have both a time-based vesting component and a performance-based vesting component, as follows:

Time-based vesting component: restricted stock awards vest in four equal annual installments beginning on the first anniversary of the date of grant.

Performance-based vesting component: restricted stock awards vest if we (or our successor) achieve any one of the following performance goals during 2010:

aggregate annual production of oil and natural gas meets or exceeds 15.6 MMBOE, as adjusted for divestitures;

proved developed producing reserves as of December 31, 2009 should not have negative forecast revisions in excess of one percent;

the development cost per Bbl of oil should not exceed $22.00;

EBITDAX (earnings before interest, income taxes, depletion, depreciation, amortization, and exploration costs) should be at least $534 million;

EBITDAX per BOE should be at least 60 percent of wellhead revenues; or

proved oil and natural gas reserves at December 31, 2010 should be greater than 220.3 MMBOE using the price in our Miller and Lents Reserve Report as of December 31, 2009, as adjusted for divestitures.

Restricted stock awards granted prior to February 2010 are subject to accelerated vesting in the event of a change in control or termination of employment due to death or disability and to such other terms as are set forth in the award agreement. In the merger agreement with Denbury, we agreed that restricted shares granted with respect to calendar year 2009 would not vest at the effective time of the merger, but would be converted into a number of restricted shares of Denbury common stock determined by multiplying (1) the number of restricted shares of EAC common stock subject to that grant by (2) the exchange ratio used in determining the consideration payable to EAC stockholders who have elected to receive only common stock consideration. However, the restricted shares of Denbury common stock will vest if the EAC employee is terminated without cause or resigns for good reason at or after the effective time of the merger.

Stock Options. The Compensation Committee generally grants stock options with a value equal to the value of the annual cash bonus. However, under the merger agreement with Denbury, we agreed not to grant

158

ENCORE ACQUISITION COMPANY

stock options as part of equity incentive compensation for 2009 and, in lieu thereof, agreed to make additional grants of restricted stock.

Special Bonus

Under the merger agreement, the Compensation Committee is also permitted to pay additional bonuses to EAC employees (other than the Chief Executive Officer) in an amount not to exceed $1,000,000, of which $300,000 was awarded to Mr. Reeves, $250,000 was awarded to Mr. Arms, and $450,000 was awarded to other EAC employees.

Perquisites and Other Benefits

Perquisites. Our named executive officers generally do not receive benefits that are not available to all employees. For example, we provide all employees with health club membership options. During 2009, the aggregate value of all perquisites did not exceed $10,000 for any named executive officer except for Mr. I. Jon Brumley s personal use of EAC s aircraft, which was valued at $12,007.

In February 2008, the Compensation Committee approved personal use of EAC s aircraft for Mr. I. Jon Brumley and Mr. Jon S. Brumley. Both executives are allowed personal use of EAC s aircraft without charge for up to a maximum of 15 hours per year. For any personal use in excess of 15 hours a year, the executive will be required to reimburse us for variable costs related to such use, such as jet fuel, variable crew costs, flight insurance, landing fees, flight planning fees, and airport taxes. The executive will also be required to pay us an additional amount equal to 10 percent of jet fuel relating to personal use in excess of 15 hours per year.

Other Benefits. We seek to provide benefit plans, such as medical, life, and disability insurance, in line with market conditions. Executive officers are eligible for the same benefit plans provided to other exempt employees, including insurance plans and supplemental plans chosen and paid for by employees who want additional coverage. We do not have any special insurance plans for executive officers.

Post-Employment Benefits

We have an employee severance protection plan that provides all full-time employees with severance payments and benefits upon certain terminations of employment occurring from 90 days prior to until two years following a change in control (as defined in the plan). If during such time period, a named executive officer is involuntarily terminated by us or our successor other than for cause or he resigns for good reason (as defined in the plan), the officer will receive the following:

- cash equal to 2 to 3 times annual salary and cash bonus;
- continued medical, dental, and life insurance coverage for up to three years;
- automatic vesting of all stock options and restricted stock; and
- an additional amount to gross up the amount, if any, of excise tax payable by the officer under the golden parachute provisions of the Code such that after payment of excise and income taxes on the gross up payment, the officer will retain an amount sufficient to cover the excise tax.

For more information regarding the employee severance protection plan, including potential payments, please read Potential Payments Upon Termination or Change in Control Change in Control.

Stock Ownership Guidelines

The Compensation Committee has adopted stock ownership guidelines that require each named executive officer (and certain other members of management) to own shares of our common stock with a value at least equal to such person s base salary. Until this guideline is achieved, the named executive officer (or other

ENCORE ACQUISITION COMPANY

member of management) will be required to retain at least 25 percent of his or her restricted stock for a period of two years after vesting. Our stock ownership guidelines are designed to increase executives equity stakes in us and to align executives interests more closely with those of our stockholders.

Impact of Tax Treatment

Section 162(m) of the Code generally disallows a tax deduction to public companies for compensation in excess of $1,000,000 paid to the Chief Executive Officer and each of the three other highest paid officers (other than the Chief Financial Officer). Performance-based compensation arrangements may qualify for an exemption from the deduction limit if they satisfy various requirements under Section 162(m). Although we consider the impact of this rule when developing and implementing our executive compensation program, we believe that it is important to preserve flexibility in designing compensation programs. Accordingly, we have not adopted a policy that all compensation must qualify as deductible under Section 162(m). While our performance-based restricted stock, stock option, and Bonus Plan awards are intended to meet the requirements for qualified performance-based compensation (as defined in the Code), amounts paid under our other compensation programs may not qualify for this exemption.

Compensation Committee Report

The Compensation Committee of the Board has reviewed and discussed with our management the Compensation Discussion and Analysis included in this Form 10-K. Based on that review and discussion, the Compensation Committee has recommended to the Board that the Compensation Discussion and Analysis be included in this Form 10-K.

The information contained in this report shall not be deemed to be soliciting material or filed or incorporated by reference in future filings with the SEC, or subject to the liabilities of Section 18 of the Exchange Act, except to the extent that EAC specifically incorporates it by reference into a document filed under the Securities Act of 1933 or the Exchange Act.

Compensation Committee of the Board

James A. Winne III, Chairman
Martin C. Bowen
Ted Collins, Jr.

Table of Contents

ENCORE ACQUISITION COMPANY

Summary Compensation Table

The following table summarizes the total compensation awarded to, earned by, or paid to our named executive officers for the periods indicated:

e and Title	Year	Salary	Cash Bonus	Stock Awards(a) EAC Restricted Stock(b)	ENP MIUs	Option Awards(b) (c)	Non-Equity Incentive Plan Compensation	Change in Pension Value and Nonqualified Deferred Compensation Earnings	All Other Compensation(d) (e)	Total
n Brumley rman of the	2009	$ 384,417	$ 772,600	$ 879,871	$	$ 439,945	$	$	$ 34,057	$ 2,510,
d	2008	370,833	439,900		1,236,785				46,856	2,094,
	2007	350,000	700,000	1,968,626	1,769,074	26,271			19,688	4,833,
. Brumley f Executive	2009	615,000	1,545,000	1,016,809		512,501			22,050	3,711,
er	2008	591,667	791,900	715,725	1,236,785	227,234			41,544	3,604,
President	2007	537,500	850,000	1,040,528	1,769,074	535,732			19,688	4,752,
rt C. Reeves or Vice	2009	369,000	648,900	423,692		229,481			22,050	1,693,
dent, f Financial	2008	351,667	372,700	219,411	951,373	103,516			20,700	2,019,
er, surer, and orate etary	2007	295,833	550,000	304,680	1,360,826	163,483			19,688	2,694,
en Nivens or Vice	2009	369,000	741,600	391,144		219,757			22,050	1,743,
dent Chief	2008	349,167	369,500	153,012	665,961	77,698			20,700	1,636,
ating er	2007	287,500	550,000	218,911	952,578	110,250			19,688	2,138,

W. Arms	2009	333,167	418,500	340,842		184,936	22,050	1,299,
or Vice								
dent,	2008	312,500	302,800	172,227	665,961	76,637	20,700	1,550,
isitions	2007	241,667	475,000	232,084	952,578	126,599	19,688	2,047,

(a) Reflects the compensation cost recognized by us with respect to grants of restricted stock awards and management incentive units, which does not correspond to the actual value that may be realized by the named executive officers. Pursuant to SEC rules, the amounts shown exclude the impact of estimated forfeitures related to service-based vesting conditions.

(b) During 2008, our named executive officers did not receive any grants of restricted stock or stock options with respect to performance in 2007 because, as named executive officers of ENP s general partner, they received a grant of management incentive units in May 2007.

(c) This amount reflects the compensation cost recognized by us with respect to grants of stock options. Pursuant to SEC rules, the amounts shown exclude the impact of estimated forfeitures related to service-based vesting conditions. The grant date fair value of each option was estimated utilizing the Black-Scholes option-pricing model using the following assumptions:

	Year Ended December 31,			
	2009	**2007**	**2006**	**2005**
Expected volatility	51.9%	35.7%	42.8%	46.0%
Expected dividend yield	0.0%	0.0%	0.0%	0.0%
Expected term (in years)	6.25	6.0	6.0	6.0
Risk-free interest rate	2.1%	4.8%	4.6%	3.7%
Weighted-average grant-date fair value per share	$ 15.81	$ 11.16	$ 14.96	$ 12.99

These amounts reflect our recognized compensation expense for these awards, and do not correspond to the actual value that may be realized by the named executive officers.

(d) Includes matching contributions to our 401(k) plan of $22,050, $20,700, and $19,688, for each named executive officer in 2009, 2008, and 2007, respectively.

(e) For I. Jon Brumley, includes $12,007 and $26,156 related to personal use of our aircraft during 2009 and 2008, respectively. For Jon S. Brumley, includes $20,844 related to personal use of our aircraft during 2008.

Table of Contents

ENCORE ACQUISITION COMPANY

Grants of Plan-Based Awards for 2009

The following tables contain information with respect to EAC s grant of plan-based awards to the named executive officers in 2009 with respect to performance during 2008:

Name	Grant Date	Estimated Future Payouts Under Equity Incentive Plan Awards Threshold (#)	Target (#)	Maximum (#)	All Other Option Awards: Number of Securities Underlying	Exercise or Base Price of Option Awards	Grant Date Fair Value of Awards (a)
I. Jon Brumley	2/9/2009		28,801		27,827	$ 30.55	$ 1,319,816
Jon S. Brumley	2/9/2009		51,842		50,088	30.55	2,375,664
Robert C. Reeves	2/9/2009		24,396		23,571	30.55	1,117,956
L. Ben Nivens	2/9/2009		24,193		23,374	30.55	1,108,639
John W. Arms	2/9/2009		19,822		19,151	30.55	908,339

(a) The grant date fair value of each EAC restricted stock and option award is as follows:

Name	Restricted Stock	Shares Options	Total Reflected in Grant Date Fair Value Column
I. Jon Brumley	$ 879,871	$ 439,945	$ 1,319,816
Jon S. Brumley	1,583,773	791,891	2,375,664
Robert C. Reeves	745,298	372,658	1,117,956
L. Ben Nivens	739,096	369,543	1,108,639
John W. Arms	605,562	302,777	908,339

Restricted stock awards granted to our named executive officers (and certain other members of management) during 2009 have time-based and performance-based vesting components, as follows:

Time-based vesting component: restricted stock awards vest in four equal annual installments beginning on the first anniversary of the date of grant.

Performance-based vesting component: restricted stock awards vest if we achieve any one of the following performance goals during 2010:

meet budgeted volumes;

achieve negative forecast revisions for proved developed producing properties of one percent or less;

generate at least $150 million of free cash flow;

achieve development costs of $22 per Bbl or less; and

generate a 15 percent rate of return based on constant oil and natural gas prices.

Restricted stock awards are subject to accelerated vesting in the event of a change in control or termination of employment due to death or disability and to such other terms as are set forth in the award agreement.

On February 8, 2010, the Compensation Committee determined that we had satisfied at least one of the performance-based conditions with respect to the restricted stock awards granted during 2009 and, therefore, such awards are now subject only to the time-based vesting component.

Table of Contents

ENCORE ACQUISITION COMPANY

Outstanding Equity Awards at December 31, 2009

The following table sets forth information concerning the outstanding equity awards held by each named executive officer as of December 31, 2009:

		Option Awards(a)(b)				Stock Awards(a)			
		Number of Securities Underlying Unexercised Options							
me and Title	Grant Date	Exercisable	Unexercisable	Option Exercise Price	Option Expiration Date	Number of Shares or Units of Stock That Have Not Vested(c)	Market Value of Shares or Units of Stock That Have Not Vested(d)	Equity Incentive Plan Awards: Number of Unearned Shares, Units or Other Rights That Have Not Vested(c)	Equit Incent Plan Aware Mark or Payou Valu of Unearr Share Unit or Othe Righ Tha Hav Not Vested
on Brumley airman of the	03/08/2001	44,357		$ 9.3333	03/08/2011	N/A	N/A	N/A	N/
ard	10/23/2001	60,000		8.4000	10/23/2011	N/A	N/A	N/A	N/
	11/22/2002	130,644		12.4000	11/22/2012	N/A	N/A	N/A	N/
	02/10/2004	93,361		17.1733	02/10/2014	N/A	N/A	N/A	N/
	02/14/2005					26,375	$ 1,266,528	N/A	N/
	02/15/2006					16,881	810,626	N/A	N/
	02/12/2007					24,776	1,189,744	N/A	N/
	02/09/2009		27,827	30.5500	02/09/2019	28,801	1,383,024	N/A	N/
n S. Brumley ief Executive	03/08/2001	68,500		$ 9.3333	03/08/2011	N/A	N/A	N/A	N/
ficer	10/23/2001	60,000		8.4000	10/23/2011	N/A	N/A	N/A	N/
l President	11/22/2002	58,065		12.4000	11/22/2012	N/A	N/A	N/A	N/

	02/10/2004	68,464		17.1733	02/10/2014	N/A	N/A	N/A	N/
	02/14/2005	30,269		26.5467	02/14/2015	11,300	$ 542,626	N/A	N/
	02/15/2006	29,949		31.1000	02/15/2016	8,440	405,289	N/A	N/
	02/12/2007	28,376	14,187	25.7300	02/12/2017	18,460	886,449	N/A	N/
	02/09/2009		50,088	30.5500	02/09/2019	51,842	2,489,453	N/A	N/
bert C. Reeves	03/08/2001	10,179		$ 9.3333	03/08/2011	N/A	N/A	N/A	N/
nior Vice									
esident,	10/23/2001	30,000		8.4000	10/23/2011	N/A	N/A	N/A	N/
ief Financial									
ficer,	11/22/2002	15,483		12.4000	11/22/2012	N/A	N/A	N/A	N/
easurer, and	02/10/2004	12,448		17.1733	02/10/2014	N/A	N/A	N/A	N/
rporate Secretary	02/14/2005	5,040		26.5467	02/14/2015	1,885	$ 90,518	N/A	N/
	02/15/2006	5,134		31.1000	02/15/2016	1,447	69,485	N/A	N/
	02/12/2007	12,694	6,347	25.7300	02/12/2017	8,258	396,549	N/A	N/
	02/09/2009		23,571	30.5500	02/09/2019	24,396	1,171,496	N/A	N/
Ben Nivens	11/22/2002	296		$ 12.4000	11/22/2012	N/A	N/A	N/A	N/
nior Vice									
esident	11/21/2003	809		13.6067	11/21/2013	N/A	N/A	N/A	N/
d Chief Operating	02/14/2005	642		26.5467	02/14/2015	479	$ 23,002	N/A	N/
ficer	02/15/2006	5,705		31.1000	02/15/2016	1,607	77,168	N/A	N/
	02/12/2007	8,960	4,481	25.7300	02/12/2017	5,830	279,957	N/A	N/
	02/09/2009		23,374	30.5500	02/09/2019	24,193	1,161,748	N/A	N/
n W. Arms	03/08/2001	13,125		$ 9.3333	03/08/2011	N/A	N/A	N/A	N/
nior Vice									
esident,	10/23/2001	8,475		8.4000	10/23/2011	N/A	N/A	N/A	N/
quisitions	11/22/2002	7,741		12.4000	11/22/2012	N/A	N/A	N/A	N/
	02/10/2004	4,979		17.1733	02/10/2014	N/A	N/A	N/A	N/
	02/14/2005	5,040		26.5467	02/14/2015	1,885	$ 90,518	N/A	N/
	02/15/2006	4,849		31.1000	02/15/2016	1,366	65,595	N/A	N/
	02/12/2007	8,960	4,481	25.7300	02/12/2017	5,830	279,957	N/A	N/
	02/09/2009		19,151	30.5500	02/09/2019	19,822	951,852	N/A	N/

(a) Grants prior to 2006 have been adjusted to reflect EAC s three-for-two stock split in July 2005.

(b) EAC stock options vest and become exercisable in three equal annual installments beginning on the first anniversary of the grant date.

(c) EAC restricted stock awards granted prior to 2005 vest in three equal annual installments beginning on the third anniversary of the grant date. EAC restricted stock awards granted subsequent to 2005 vest in four equal annual installments beginning on the first anniversary of the grant date. All EAC restricted stock awards are subject to forfeiture if certain performance objectives are not satisfied and to accelerated vesting in the event of a change in control or termination of employment due to death or disability and to such other terms as are set forth in the award agreement. Holders of EAC restricted stock have the right to vote and to receive dividends paid with respect to shares of restricted stock.

(d) Calculated using the closing price of our common stock on the NYSE on December 31, 2009 of $48.02 per share.

Table of Contents

ENCORE ACQUISITION COMPANY

Option Exercises and Stock Vested

The following table summarizes option exercises and the vesting of restricted stock awards during 2009 for each named executive officer:

	Option Awards		Stock Awards	
Name	Number of Shares Acquired on Exercise	Value Realized on Exercise	Number of Shares Acquired on Vesting (a)	Value Realized on Vesting(b)
I. Jon Brumley		$	69,784	$ 1,868,246
Jon S. Brumley			34,156	906,622
Robert C. Reeves			8,404	220,299
L. Ben Nivens			5,002	129,180
John W. Arms			6,543	170,884

(a) Represents shares of restricted stock that vested on various dates during 2009.

(b) Determined by multiplying the number of shares of restricted stock by the closing price on the NYSE of EAC s common stock on the vesting date.

Pension Benefits

We do not maintain any plans that provide for payments or other benefits at, following, or in connection with retirement.

Non-Qualified Deferred Compensation

We do not maintain any defined contribution or other plan that provides for the deferral of compensation on a basis that is not tax-qualified under the Code.

Potential Payments Upon Termination or Change in Control

Cash Severance

Except as described below under Change in Control, our employees do not receive any cash severance payments in connection with a termination of employment. In the past, we have paid certain executive officers a cash severance on a case-by-case basis in exchange for a release and agreement to certain post-employment covenants.

Stock Options and Restricted Stock Awards

All salaried employees who receive stock options or restricted stock awards are subject to the same terms and conditions in the event of a termination or change in control.

Termination other than upon Normal Retirement, Change in Control, Death, or Disability. Upon termination other than upon normal retirement, change in control, death, or disability, options may be exercised to the extent exercisable at termination for a period of three months and any unvested restricted stock is forfeited.

Termination upon Normal Retirement. All salaried employees who receive restricted stock awards continue to vest upon normal retirement as if they were still employed by us. There are no special provisions related to retirement under our stock option agreements for grants prior to February 2009. Upon termination for any reason other than death, disability, or in connection with a change in control, options granted prior to February 2009 may be exercised to the extent exercisable at termination for a period of three months. All salaried employees who receive stock option awards during or subsequent to February 2009 continue to vest upon normal retirement as if they were still employed by us.

ENCORE ACQUISITION COMPANY

Termination upon Change in Control. Upon a change in control (as described below under Change in Control), unless otherwise determined by the Compensation Committee, all options and restricted stock awards will immediately vest and become exercisable and all transfer restrictions and vesting requirements on options and restricted stock awards will lapse. In such event, all awards will be cashed out based on the highest price per share paid in connection with the change in control transaction.

Termination upon Death or Disability. Upon death or disability, all stock options become fully exercisable and remain exercisable for two years (or the remaining term, if less). Upon death, all restricted stock awards vest as to service-based vesting conditions, but remain subject to the performance-based vesting conditions. Upon disability, all restricted stock awards continue to vest as if the participant were still employed by us, provided that if the participant remains disabled after 18 months, then the service-based vesting condition shall be deemed satisfied, but such awards shall remain subject to any performance-based vesting conditions.

Change in Control

The Board has adopted a Employee Severance Protection Plan, which provides all full-time employees with severance payments and benefits upon certain terminations of employment occurring from 90 days prior to until two years following a change in control (as described below). Our plan is considered a double-trigger plan that requires not only a change in control but also a termination of employment. If during such time period, a named executive officer is involuntarily terminated by us or our successor other than for cause or he resigns for good reason (as described below), the officer will receive the following:

- cash equal to 2 to 3 times annual salary and bonus;
- continued medical, dental, and life insurance coverage for up to three years;
- automatic vesting of all stock options and restricted stock; and
- an additional amount to gross up the amount, if any, of excise tax payable by the officer under the golden parachute provisions of the Code such that after payment of excise and income taxes on the gross up payment, the officer will retain an amount sufficient to cover the excise tax.

The Employee Severance Protection Plan obligates us to maintain a minimum level of director and officer liability insurance for a period of three years following the date any officer is entitled to benefits under the plan.

Generally, a change in control occurs upon: (1) the acquisition by a party of 40 percent or more of the voting securities of EAC unless the party owned 20 percent prior to February 11, 2003; (2) a majority of the Board no longer consists of persons who were Board members on February 11, 2002 or persons appointed to the Board by those members (Incumbent Directors); (3) the approval by EAC s stockholders of a complete liquidation or dissolution; or (4) the approval by EAC s stockholders of a reorganization, merger, share exchange, consolidation, or a sale of all or substantially all of EAC s assets, unless (1) more than 60 percent of the voting securities of the new entity are held by persons who were EAC stockholders immediately prior to the transaction, (2) no person holds more than 40 percent of the new entity, unless such person held 40 percent of the voting securities immediately prior to the transaction, and (3) a majority of the board of the new entity are Incumbent Directors. A resignation for good reason occurs when an officer resigns as a result of a reduction in titles, duties, responsibilities, or compensation level, or the relocation of place of employment of greater than 50 miles.

Table of Contents

ENCORE ACQUISITION COMPANY

Potential Payments

Change in Control. The following table shows the potential payments to our named executive officers under the Employee Severance Protection Plan, assuming that the employee was involuntarily terminated or resigned for good reason in connection with a change in control on December 31, 2009:

	I. Jon Brumley	Jon S. Brumley	Robert C. Reeves	L. Ben Nivens	John W. Arms
Cash severance	$ 2,317,800	$ 5,407,500	$ 2,039,400	$ 2,224,800	$ 1,506,600
Insurance coverage	66,104	67,603	67,603	31,265	67,231
Stock options(a)	486,138	1,191,266	553,260	508,225	434,449
Restricted stock(b)	4,698,904	4,351,321	1,736,393	1,547,574	1,394,412
Tax gross up		2,293,860	903,506	994,027	677,790
Total	$ 7,568,946	$ 13,311,550	$ 5,300,162	$ 5,305,891	$ 4,080,482

(a) Option awards will automatically vest upon a change in control even without a termination of employment. Under EAC s incentive stock plans, stock options will be cashed out in the event of a change in control at their fair value on the date the event occurs. Accordingly, these amounts have been calculated by multiplying the number of previously unvested stock options by the difference between $48.02 per share, the closing price of EAC s common stock on the NYSE on December 31, 2009, and the exercise price of the previously unvested stock options. Amounts which would be payable with respect to vested options are not included in the table.

(b) Restricted stock awards will automatically vest upon a change in control even without a termination of employment. Restricted stock awards under EAC s 2000 Incentive Stock Plan will be cashed out in the event of a change in control at the highest closing price per share paid for our stock within the 60 days prior to the change in control. Accordingly, the payment on a change in control for awards under the 2000 Incentive Stock Plan has been calculated by multiplying the number of previously unvested shares of restricted stock by $48.74 per share, which was the highest closing price paid for EAC s common stock on the NYSE in the 60 days prior to December 31, 2009.

Death, Disability, or Other Termination of Employment. The following table shows the potential payments to our named executive officers pursuant to the terms of EAC s restricted stock and option awards, assuming the death, disability, or other termination of the employee on December 31, 2009:

	I. Jon Brumley	Jon S. Brumley	Robert C. Reeves	L. Ben Nivens	John W. Arms
Death(a)(c)	$ 5,136,058	$ 5,515,082	$ 2,281,308	$ 2,050,099	$ 1,822,324
Disability(b)(c)	486,138	1,191,266	553,260	508,225	434,449
Any other termination					

(a) Reflects the automatic vesting of EAC stock options and restricted stock.

(b) Reflects the automatic vesting of EAC stock options.

(c) With respect to stock options, the payment is determined by multiplying the number of unvested stock options by the difference between $48.02 per share, the closing price of EAC s common stock on the NYSE on December 31, 2009, and the exercise price of the previously unvested stock options. With respect to restricted stock, the payment is determined by multiplying the number of unvested shares of restricted stock by $48.02 per share, the closing price of EAC s common stock on the NYSE on December 31, 2009.

For information on the continued vesting of restricted stock awards and stock option awards following disability or retirement, please read Stock Options and Restricted Stock Awards above.

Table of Contents

ENCORE ACQUISITION COMPANY

Compensation Committee Interlocks and Insider Participation

During 2009 and as of the date of this Report, no member of the Compensation Committee is or has been an officer or employee of EAC and no executive officer of EAC served on the compensation committee or board of any entity that employed any member of the Board.

Director Compensation

Officers or employees of us or our affiliates who also serve as directors do not receive additional compensation for their service as a director. Each director is fully indemnified by us for actions associated with being a director to the extent permitted under Delaware law.

The following table sets forth a summary of the compensation paid to or earned by non-employee directors in 2009:

Name	Fees Earned or Paid in Cash(a)	Stock Awards(b)	Option Awards	Non-Equity Incentive Plan Compensation	Change in Pension Value and Nonqualified Deferred Compensation Earnings	All Other Compensation	Total(c)
John A. Bailey	$ 82,000	$ 145,600	$	$	$	$	$ 227,600
Martin C. Bowen	71,000	145,600					216,600
Ted Collins, Jr.	86,000	145,600					231,600
Ted A. Gardner	92,000	145,600					237,600
John V. Genova	82,000	145,600					227,600
James A. Winne III	86,000	145,600					231,600

(a) Directors receive an annual retainer of $50,000 plus additional fees of $2,000 for attendance at each Board meeting and $1,000 for attendance at each committee meeting. The chair of each committee receives an additional annual fee of $10,000.

(b) Directors receive an annual grant of 5,000 shares of restricted stock under our long-term incentive plan. Amount is determined by multiplying the number of shares of restricted stock granted by $29.12, the closing price of our common stock on the NYSE on April 28, 2009, which was the date of grant. Shares of restricted stock vest in four equal annual installments beginning on the first anniversary of the grant date, subject to immediate vesting in the event of a change in control or termination of employment due to death or disability and to such other terms as are set forth in the award agreement.

(c) We also reimburse directors for out-of-pocket expenses attendant to Board membership. These amounts are excluded from the above table.

ITEM 12. *SECURITY OWNERSHIP OF CERTAIN BENEFICIAL OWNERS AND MANAGEMENT AND RELATED STOCKHOLDER MATTERS*

The following table sets forth the beneficial ownership of our outstanding common stock as of February 17, 2010 by:

- each person known by us to beneficially own more than 5 percent of our outstanding common stock;
- each member of the board of directors;
- each of our named executive officers; and
- all of our directors and executive officers as a group.

Unless otherwise noted, the persons named below have sole voting and investment power with respect to such shares.

Table of Contents

ENCORE ACQUISITION COMPANY

Name and Address of Beneficial Owner	Shares Beneficially Owned	Percent of Class
5% Beneficial Owners		
Baron Capital Group, Inc.(c) 767 Fifth Avenue, 49th Floor New York, New York 10153	3,706,707	6.6%
BlackRock, Inc.(d) 40 East 52nd Street New York, New York 10022	2,962,343	5.3%
Directors and Named Executive Officers(a)(b)		
I. Jon Brumley(e)	2,615,105	4.6%
Jon S. Brumley	1,087,115	1.9%
Robert C. Reeves	221,512	*
L. Ben Nivens	122,528	*
John W. Arms	152,442	*
John A. Bailey	20,000	*
Martin C. Bowen	42,000	*
Ted Collins, Jr.	147,750	*
Ted A. Gardner	34,500	*
John V. Genova	34,500	*
James A. Winne III	42,500	*
All directors and executive officers as a group (15 persons)	4,868,454	8.5%

* Less than 1%.

(a) Includes options that are or become exercisable within 60 days of February 17, 2010 as follows: Mr. I. Jon Brumley (337,638), Mr. Jon S. Brumley (374,506), Mr. Reeves (105,182), Mr. Nivens (28,685), Mr. Arms (64,034), Mr. Bowen (7,500), Mr. Collins (18,000), Mr. Gardner (15,000), Mr. Genova (7,500), and Mr. Winne (18,000), and all directors and executive officers as a group (1,167,748).

(b) Includes unvested restricted stock as of February 17, 2010 as follows: Mr. I. Jon Brumley (81,552), Mr. Jon S. Brumley (143,227), Mr. Reeves (62,375), Mr. Nivens (66,715), Mr. Arms (43,545), Mr. Bailey (12,500), Mr. Bowen (14,000), Mr. Collins (14,000), Mr. Gardner (14,000), Mr. Genova (14,000), and Mr. Winne (14,000), and all directors and executive officers as a group (568,500).

(c) Based on an amendment to Schedule 13G filed with the SEC on February 8, 2010 by Baron Capital Group, Inc. (BCG), BAMCO, Inc., an investment advisor (BAMCO), Baron Capital Management, Inc., an investment advisor (BCM), Baron Growth Fund, a registered investment company (BGF), and Ronald Baron. Such filing indicated: (1) BCG had shared voting power with respect to 3,251,207 shares and shared dispositive power with respect to 3,706,707 shares; (2) BAMCO had shared voting power with respect to 3,251,493 shares and shared dispositive power with respect to 3,479,100 shares; (3) BCM had shared voting power with respect to

217,107 shares and shared dispositive power with respect to 227,607 shares; (4) BGF had shared voting and dispositive power with respect to 2,800,000 shares; and (5) Ronald Baron had shared voting power with respect to 3,251,207 shares and shared dispositive power with respect to 3,706,707 shares. BAMCO and BCM are subsidiaries of BCG. BGF is an advisory client of BAMCO. Ronald Baron owns a controlling interest in BCG. By virtue of investment advisory agreements with their respective clients, BAMCO and BCM have been given the discretion to dispose or to direct the disposition of the securities in the advisory accounts. BCG and Ronald Baron disclaim beneficial ownership of shares held by their controlled entities (or the investment advisory clients thereof) to the extent such shares are held by persons other than BCG and Ronald Baron. BAMCO and BCM disclaim

Table of Contents

ENCORE ACQUISITION COMPANY

beneficial ownership of shares held by their investment advisory clients to the extent such shares are held by persons other than BAMCO, BCM, and their affiliates.

(d) Based on an amendment to Schedule 13G filed with the SEC on December 14, 2009 by BlackRock, Inc. (BlackRock). Such filing indicated that BlackRock had sole voting and dispositive power with respect to 2,962,343 shares.

(e) Mr. Brumley is the sole officer, director, and stockholder of a corporation that is the sole general partner of two limited partnerships that own a total of 1,945,013 shares. Accordingly, Mr. Brumley had sole voting and dispositive power with respect to all shares owned by these partnerships.

The following table sets forth information about our common stock that may be issued under equity-based compensation plans as of December 31, 2009:

	(a) Number of Securities to Be Issued upon Exercise of Outstanding Options, Warrants and Rights(a)	(b) Weighted-Average Exercise Price of Outstanding Options, Warrants and Rights	(c) Number of Securities Remaining Available for Future Issuance Under Equity Compensation Plans (Excluding Securities Reflected in Column (a))
Equity compensation plans approved by security holders	1,729,591	$ 19.84	1,717,787
Equity compensation plans not approved by security holders		$	
Total	1,729,591	$ 19.84	1,717,787

(a) There are no outstanding warrants or equity rights awarded under our equity compensation plans. Excludes 920,122 shares of unvested restricted stock.

For discussion of our equity-based compensation plans, please read Item 11. Executive Compensation.

ITEM 13.

CERTAIN RELATIONSHIPS AND RELATED TRANSACTIONS, AND DIRECTOR INDEPENDENCE

Policies and Procedures for Approval of Related Person Transactions

The Board has adopted a policy with respect to related person transactions to document procedures pursuant to which such transactions are reviewed, approved, or ratified. The policy applies to any transaction in which:

- EAC is a participant;
- any related person has a direct or indirect material interest; and
- the amount involved exceeds $120,000, but excludes any transaction that does not require disclosure under Item 404(a) of Regulation S-K.

The Nominating and Corporate Governance Committee is responsible for reviewing, approving, and ratifying any related person transaction.

Director Independence

All members of the Board, other than Mr. I. Jon Brumley and Mr. Jon S. Brumley, are independent as defined under the independence standards established by the NYSE.

Table of Contents

ENCORE ACQUISITION COMPANY

ITEM 14. *PRINCIPAL ACCOUNTANT FEES AND SERVICES*

The Audit Committee appointed Ernst & Young LLP as our independent registered public accounting firm for 2010.

Fees Incurred by Us for Services Provided by Ernst & Young LLP

The following table shows the fees paid or accrued by us for services provided by Ernst & Young LLP during the periods indicated:

	2009	2008
Audit fees(a)	$ 2,117,795	$ 1,524,531
Audit-related fees		
Tax fees		
All other fees(b)	1,995	6,000
Total	$ 2,119,790	$ 1,530,531

(a) Represent fees for professional services provided in connection with: (1) the annual audit of our consolidated financial statements; (2) the annual audit of our internal control over financial reporting; (3) the review of our quarterly consolidated financial statements; and (4) audit services provided in connection with SEC filings, including comfort letters, consents, and comment letters. Includes ENP audit fees of $1,038,847 and $868,471 during 2009 and 2008, respectively.

(b) Consists of amounts paid for access to EY/Online, an Internet-based resource for accounting and auditing matters.

Audit Committee s Pre-Approval Policy and Procedures

The Audit Committee s policy is to pre-approve all audit and permissible non-audit services provided by our independent registered public accounting firm. These services may include audit services, audit-related services, tax services, and other services. Pre-approval is detailed as to the particular service or category of service and is subject to a specific approval. The Audit Committee requires our independent registered public accounting firm and management to report on the actual fees charged for each category of service at Audit Committee meetings throughout the year.

During the year, circumstances may arise when it may become necessary to engage our independent registered public accounting firm for additional services not contemplated in the original pre-approval. In those instances, the Audit Committee requires specific pre-approval before engaging our independent registered public accounting firm. The Audit Committee has delegated pre-approval authority to its chairman for those instances when pre-approval is needed prior to a scheduled Audit Committee meeting. The chairman of the Audit Committee must report on such approvals at the next scheduled Audit Committee meeting.

All services provided by our independent registered public accounting firm were pre-approved.

ENCORE ACQUISITION COMPANY

PART IV

ITEM 15. *EXHIBITS AND FINANCIAL STATEMENT SCHEDULES*

(a) The following documents are filed as a part of this Report:

1. Financial Statements:

2. Financial Statement Schedules:

All financial statement schedules have been omitted because they are not applicable or the required information is presented in the financial statements or the notes to the consolidated financial statements.

(b) Exhibits

Table of Contents

ENCORE ACQUISITION COMPANY

Exhibit No.	Description
2.1	Agreement and Plan of Merger dated as of October 31, 2009 by and between Encore Acquisition Company and Denbury Resources Inc. (incorporated by reference from Exhibit 2.1 to EAC s Current Report on Form 8-K, filed with the SEC on November 3, 2009).
3.1	Second Amended and Restated Certificate of Incorporation of Encore Acquisition Company EAC (incorporated by reference from Exhibit 3.1 to EAC s Quarterly Report on Form 10-Q for the quarter ended September 30, 2001, filed with the SEC on November 7, 2001).
3.1.2	Certificate of Amendment to Second Amended and Restated Certificate of Incorporation of Encore Acquisition Company (incorporated by reference from Exhibit 3.1.2 to EAC s Quarterly Report on Form 10-Q for the quarter ended March 31, 2005, filed with the SEC on May 5, 2005).
3.1.3	Certificate of Designations of Series A Junior Participating Preferred Stock of Encore Acquisition Company (incorporated by reference from Exhibit 3.1 to EAC s Current Report on Form 8-K, filed with the SEC on October 31, 2008).
3.2	Second Amended and Restated Bylaws of Encore Acquisition Company (incorporated by reference from 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	Specimen certificate of Encore Acquisition Company (incorporated by referenced from Exhibit 4.1 to EAC s Registration Statement on Form S-1, Registration No. 333-47540, filed with the SEC on December 15, 2000).
4.2.1	Indenture, dated as of April 2, 2004, among Encore Acquisition Company, the subsidiary guarantors party thereto and Wells Fargo Bank, National Association, with respect to the 6.25% Senior Subordinated Notes due 2014 (incorporated by reference from Exhibit 4.1 of EAC s Registration Statement on Form S-4 (Registration No. 333-117025) filed with the SEC on June 30, 2004).
4.2.2	Form of 6.25% Senior Subordinated Note to Cede & Co. or its registered assigns (included as Exhibit A to Exhibit 4.2.1 above).
4.2.3	First Supplemental Indenture, dated as of January 2, 2008, among Encore Acquisition Company, the subsidiary guarantors party thereto and Wells Fargo Bank, National Association, with respect to the 6.25% Senior Subordinated Notes due 2014 (incorporated by reference from Exhibit 4.2.3 to EAC s Annual Report on Form 10-K for the year ended December 31, 2007, filed with the SEC on February 28, 2008).
4.3.1	Indenture, dated as of July 13, 2005, among Encore Acquisition Company, the subsidiary guarantors party thereto and Wells Fargo Bank, National Association, with respect to the 6.0% Senior Subordinated Notes due 2015 (incorporated by reference from Exhibit 4.1 to EAC s Current Report on Form 8-K, filed with the SEC on July 14, 2005).
4.3.2	Form of 6.0% Senior Subordinated Note due 2015 (included as Exhibit A to Exhibit 4.3.1 above).
4.3.3	First Supplemental Indenture, dated as of January 2, 2008, among Encore Acquisition Company, the subsidiary guarantors party thereto and Wells Fargo Bank, National Association, with respect to the 6.0% Senior Subordinated Notes due 2015 (incorporated by reference from Exhibit 4.3.3 to EAC s Annual Report on Form 10-K for the year ended December 31, 2007, filed with the SEC on February 28, 2008).
4.4.1	Indenture, dated as of November 16, 2005, among Encore Acquisition Company, the subsidiary guarantors party thereto 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).
4.4.2	

	First Supplemental Indenture, dated as of November 16, 2005, among Encore Acquisition Company, the subsidiary guarantors party thereto and Wells Fargo Bank, National Association, with respect to the 7.25% Senior Subordinated Notes due 2017 (incorporated by reference from Exhibit 4.2 to EAC s Current Report on Form 8-K, filed with the SEC on November 23, 2005).
4.4.3	Form of 7.25% Senior Subordinated Note due 2017 (included as Exhibit A to Exhibit 4.4.2 above).

ENCORE ACQUISITION COMPANY

Exhibit No.	Description
4.4.4	Second Supplemental Indenture, dated as of January 2, 2008, among Encore Acquisition Company, the subsidiary guarantors party thereto and Wells Fargo Bank, National Association, with respect to the 7.25% Senior Subordinated Notes due 2017 (incorporated by reference from Exhibit 4.4.4 to EAC s Annual Report on Form 10-K for the year ended December 31, 2007, filed with the SEC on February 28, 2008).
4.4.5	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).
4.4.6	Form of 9.50% Senior Subordinated Note due 2016 (included as Exhibit A to Exhibit 4.4.5 above).
4.5	Rights Agreement dated as of October 28, 2008 between Encore Acquisition Company and BNY Mellon Shareowner Services, LLC, as Rights Agent (incorporated by reference from Exhibit 4.1 to EAC s Current Report on Form 8-K, filed with the SEC on October 31, 2008).
4.5.1	First Amendment to Rights Agreement date as of October 31, 2009 between Encore Acquisition Company and BNY Mellon Shareowner Services, LLC, as Rights Agent (incorporated by reference from Exhibit 4.1 to EAC s Current Report on Form 8-K, filed with the SEC on November 3, 2009).
10.1+	2000 Incentive Stock Plan (incorporated by reference from Exhibit 4.1 to EAC s Registration Statement on Form S-8 (File No. 333-120422), filed with the SEC on November 12, 2004).
10.2+	2008 Incentive Stock Plan (incorporated by reference from Exhibit 4.5 to EAC s Registration Statement on Form S-8 (File No. 333-151323), filed with the SEC on May 30, 2008).
10.3+	Encore Acquisition Company Employee Severance Protection Plan (incorporated by reference from Exhibit 10.1 to EAC s Quarterly Report on Form 10-Q for the quarter ended September 30, 2009, filed with the SEC on November 2, 2009).
10.4+	First Amendment to Encore Acquisition Company Employee Severance Protection Plan (As Amended and Restated Effective May 6, 2008), dated as of September 29, 2009 (incorporated by reference from Exhibit 10.2 to EAC s Quarterly Report on Form 10-Q for the quarter ended September 30, 2009, filed with the SEC on November 2, 2009).
10.5+	Form of Stock Option Agreement Nonqualified (incorporated by reference from Exhibit 10.2 to EAC s Quarterly Report on Form 10-Q for the quarter ended March 31, 2009, filed with the SEC on May 6, 2009).
10.6+	Form of Stock Option Agreement Incentive (incorporated by reference from Exhibit 10.3 to EAC s Quarterly Report on Form 10-Q for the quarter ended March 31, 2009, filed with the SEC on May 6, 2009).
10.7+	Form of Restricted Stock Agreement Executive (incorporated by reference from Exhibit 10.4 to EAC s Quarterly Report on Form 10-Q for the quarter ended March 31, 2009, filed with the SEC on May 6, 2009).
10.8+	Form of Indemnification Agreement for directors and executive officers (incorporated by reference from Exhibit 10.6 of EAC s Annual Report on Form 10-K for the year ended December 31, 2004, filed with the SEC on March 10, 2005).
10.9	Description of Compensation Payable to Non-Management Directors (incorporated by reference from Exhibit 10.1 of EAC s Current Report on Form 8-K, filed with the SEC on February 22, 2006).
10.10	

	Amended and Restated Credit Agreement dated as of March 7, 2007 by and among Encore Acquisition Company, Encore Operating, L.P., Bank of America, N.A., as administrative agent and L/C Issuer, Fortis Capital Corp. and Wachovia Bank, N.A., as co-syndication agents, BNP Paribas and Calyon New York Branch, as co-documentation agents, Banc of America Securities LLC, as sole lead arranger and sole book manager, and other lenders party thereto (incorporated by reference from Exhibit 10.1 to EAC s Current Report on Form 8-K, filed with the SEC on March 13, 2007).
10.11	First Amendment to Amended and Restated Credit Agreement, dated as of January 31, 2008, by and among Encore Acquisition Company, Encore Operating, L.P., Bank of America, N.A., as administrative agent and L/C Issuer, and the lenders party thereto (incorporated by reference from Exhibit 10.1 to EAC s Current Report on Form 8-K, filed with the SEC on February 8, 2008).

Table of Contents

ENCORE ACQUISITION COMPANY

Exhibit No.	Description
10.12	Second Amendment to Amended and Restated Credit Agreement, dated as of May 22, 2008, by and among Encore Acquisition Company, Encore Operating, L.P., Bank of America, N.A., as administrative agent and L/C Issuer, and the lenders party thereto (incorporated by reference from Exhibit 99.2 to EAC s Quarterly Report on Form 10-Q for the quarter ended June 30, 2008, filed with the SEC on August 8, 2008).
10.13	Third Amendment to Amended and Restated Credit Agreement, dated as of March 10, 2009, by and among Encore Acquisition Company, Encore Operating, L.P., Bank of America, N.A., as administrative agent and L/C issuer, and the lenders party thereto (incorporated by reference from Exhibit 10.1 of EAC s Current Report on Form 8-K, filed with the SEC on March 11, 2009).
10.14	Fourth Amendment to Amended and Restated Credit Agreement, dated as of December 9, 2009, by and among Encore Acquisition Company, Encore Operating, L.P., Bank of America, N.A., as administrative agent and L/C issuer, and the lenders party thereto (incorporated by reference from Exhibit 10.1 of EAC s Current Report on Form 8-K, filed with the SEC on December 15, 2009).
10.15	Credit Agreement dated as of March 7, 2007 by and among Encore Energy Partners Operating LLC, Encore Energy Partners LP, Bank of America, N.A., as administrative agent and L/C Issuer, Banc of America Securities LLC, as sole lead arranger and sole book manager, and other lenders (incorporated by reference from Exhibit 10.2 to EAC s Current Report on Form 8-K, filed with the SEC on March 13, 2007).
10.16	First Amendment to Credit Agreement, dated August 22, 2007, by and among Encore Energy Partners Operating LLC, Encore Energy Partners LP, Bank of America, N.A., as administrative agent and L/C Issuer, Banc of America Securities LLC, as sole lead arranger and sole book manager and other lenders (incorporated by reference from Exhibit 10.1 to EAC s Current Report on Form 8-K, filed with the SEC on August 28, 2007).
10.17	Second Amendment to Credit Agreement, dated as of March 10, 2009, by and among Encore Energy Partners Operating LLC, Encore Energy Partners LP, Bank of America, N.A., as administrative agent and L/C issuer, and the lenders party thereto (incorporated by reference from Exhibit 10.1 of ENP s Current Report on Form 8-K, filed with the SEC on March 11, 2009)
10.18	Third Amendment to Credit Agreement, dated as of August 11, 2009, by and among Encore Energy Partners Operating LLC, Encore Energy Partners LP, Bank of America, N.A., as the administrative agent and L/C issuer, and the lenders party thereto (incorporated by reference from Exhibit 10.1 of ENP s Current Report on Form 8-K filed on August 13, 2009).
10.19	Fourth Amendment to Credit Agreement, dated as of November 24, 2009, by and among Encore Energy Partners Operating LLC, Encore Energy Partners LP, Bank of America, N.A., as the administrative agent and L/C issuer, and the lenders party thereto (incorporated by reference from Exhibit 10.1 of ENP s Current Report on Form 8-K, filed with the SEC on December 1, 2009).
10.20	Amended and Restated Administrative Services Agreement, dated as of September 17, 2007, by and among Encore Energy Partners GP LLC, Encore Energy Partners LP, Encore Energy Partners Operating LLC, Encore Acquisition Company and Encore Operating, L.P. (incorporated by reference from Exhibit 10.2 to EAC s Current Report on Form 8-K, filed with the SEC on September 21, 2007).
10.21	Registration Rights Agreement, dated August 18, 1998, by and among EAC and the other parties thereto (incorporated by reference to Exhibit 4.2 to EAC s Registration Statement on Form S-1 (File No. 333-47540), filed with the SEC on October 6, 2000).

10.22	Second Amended and Restated Agreement of Limited Partnership of Encore Energy Partners LP (incorporated by reference from Exhibit 10.3 to EAC s Current Report on Form 8-K, filed with the SEC on September 21, 2007)
10.23	Amendment No. 1 to Second Amended and Restated Agreement of Limited Partnership of Encore Energy Partners LP, dated as of May 10, 2007 (incorporated by reference from Exhibit 10.5 to EAC s Quarterly Report on Form 10-Q for the quarter ended March 31, 2008, filed with the SEC on May 9, 2008).
12.1*	Statement showing computation of ratios of earnings (loss) to fixed charges.
21.1*	Subsidiaries of EAC as of February 22, 2010.
23.1*	Consent of Ernst & Young LLP.

Table of Contents

ENCORE ACQUISITION COMPANY

Exhibit No.	Description
23.2*	Consent of Miller and Lents, Ltd.
24.1*	Power of Attorney (included on the signature page of this Report).
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*	Miller and Lents, Ltd. report on the Reserves and Future Net Revenues of Encore Acquisition Company as of December 31, 2009.

* Filed herewith.

\+ Management contract or compensatory plan, contract, or arrangement.

Table of Contents

ENCORE ACQUISITION COMPANY

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) 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: February 22, 2010

By: /s/ Jon S. Brumley

Jon S. Brumley
Chief Executive Officer and President

KNOW ALL MEN BY THESE PRESENTS, that each individual whose signature appears below constitutes and appoints Jon S. Brumley and Robert C. Reeves, and each of them, his true and lawful attorneys-in-fact and agents with full power of substitution, for him and in his name, place, and stead, in any and all capacities, to sign any and all amendments (including post-effective amendments) to this Report, and to file the same, with all exhibits thereto, and all documents in connection therewith, with the SEC, granting unto said attorneys-in-fact and agents, full power and authority to do and perform each and every act and thing requisite and necessary to be done in and about the premises, as fully to all intents and purposes as he might or could do in person, hereby ratifying and confirming all that said attorneys-in-fact and agents, or his or their substitutes, may lawfully do or cause to be done by virtue hereof.

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the registrant and in the capacities and on the dates indicated.

Signature	Title or Capacity	Date
/s/ I. Jon Brumley I. Jon Brumley	Chairman of the Board and Director	February 22, 2010
/s/ Jon S. Brumley Jon S. Brumley	Chief Executive Officer, President, and Director (Principal Executive Officer)	February 22, 2010
/s/ Robert C. Reeves Robert C. Reeves	Senior Vice President, Chief Financial Officer, Treasurer, and Corporate Secretary (Principal Financial Officer)	February 22, 2010
/s/ Andrea Hunter Andrea Hunter	Vice President, Controller, and Principal Accounting Officer	February 22, 2010
/s/ John A. Bailey	Director	February 22, 2010

John A. Bailey		
/s/ Martin C. Bowen	Director	February 22, 2010
Martin C. Bowen		
/s/ Ted Collins, Jr.	Director	February 22, 2010
Ted Collins, Jr.		
/s/ Ted A. Gardner	Director	February 22, 2010
Ted A. Gardner		

Table of Contents

ENCORE ACQUISITION COMPANY