ENCORE ACQUISITION CO
Form 10-K
February 28, 2008

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, 2007

or

o **TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**
For the transition period from to

Commission File Number: 001-16295

ENCORE ACQUISITION COMPANY
(Exact name of registrant as specified in its charter)

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

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

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 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. o

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

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

Indicate by check mark whether the registrant is a shell company (as defined in Exchange Act Rule 12b-2). 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, 2007 (the last business day of the registrant s most recently completed second fiscal quarter)	$1,371,310,811
Number of shares of Common Stock, $0.01 par value, outstanding as of February 20, 2008	53,400,959

DOCUMENTS INCORPORATED BY REFERENCE

Parts of the definitive proxy statement for the registrant s 2008 annual meeting of stockholders are incorporated by reference into Part III of this report on Form 10-K.

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.

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.

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.

Drill-to-Earn. The acquisition of an ownership interest in the reserves and production found and developed on properties in which no ownership interest exists prior to the onset of drilling.

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

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

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

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

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.

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

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

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

ENCORE ACQUISITION COMPANY

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

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

LIBOR. London Interbank Offered Rate.

MBbls. 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.

MMBbls. 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.

MMcf/D. One MMcf per day.

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

Net Production. Production that is owned by us less royalties, net profits interest, and production due others.

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

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.

NYMEX. New York Mercantile Exchange.

Oil. Crude oil, condensate, and NGLs.

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

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

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

Table of Contents

ENCORE ACQUISITION COMPANY

Productive Wells. Producing wells and wells capable of production, 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.

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

Proved Undeveloped Reserves. Proved reserves that are expected to be recovered from new wells drilled to known reservoirs on acreage yet to be drilled 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 to establish production. Proved undeveloped reserves include unrealized production response from fluid injection and other improved recovery techniques, such as HPAI, where such techniques have been proved effective by actual tests in the area and in the same reservoir.

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 LOE 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.

Standardized Measure. Future cash inflows from proved oil and natural gas reserves, less future LOE, development 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 income taxes.

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

Tertiary Recovery. An enhanced recovery operation, such as HPAI, that normally occurs after waterflooding in which chemicals or natural gasses 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 commercial 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 oil and natural gas from specified zones or formations.

Unsuccessful Well. A well incapable of producing oil and/or natural gas in commercial quantities.

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

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

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

Table of Contents

ENCORE ACQUISITION COMPANY

This Report contains forward-looking statements, which give our current expectations and 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 above under the caption Glossary . In addition, all production and reserve volumes disclosed in this Report represent amounts net to us.

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 our oil and natural gas reserves are located in four core areas:

- the Cedar Creek Anticline (CCA) in the Williston Basin of Montana and North Dakota;
- the Permian Basin of West Texas and southeastern New Mexico;
- the Rockies, which includes non-CCA assets in the Williston, Big Horn, and Powder River Basins of Montana, North Dakota, and Wyoming, and the Paradox Basin of southeastern Utah; and
- the Mid-Continent area, which includes the Arkoma and Anadarko Basins of Oklahoma, the North Louisiana Salt Basin, and the East Texas Basin.

On January 16, 2007, we entered into a purchase and sale agreement with certain subsidiaries of Anadarko Petroleum Corporation (Anadarko) to acquire oil and natural gas properties and related assets in the Big Horn Basin of Montana and Wyoming, 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. Prior to closing, we 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. The closing of the Big Horn Basin acquisition occurred on March 7, 2007. The total purchase price for the Big Horn Basin assets was approximately $393.6 million, including transaction costs of approximately $1.3 million.

On January 23, 2007, we entered into a purchase and sale agreement with certain subsidiaries of Anadarko to acquire oil and natural gas properties and related assets in the Williston Basin of Montana and Wyoming. The closing of the Williston Basin acquisition occurred on April 11, 2007. The total purchase price for the Williston Basin assets was approximately $392.1 million, including transaction costs of approximately $1.3 million. The properties are comprised of 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.

In February 2007, we 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) of 9,000,000 common units at a price to the public of $21.00 per unit. In October 2007, the underwriters exercised their over-allotment option to purchase 1,148,400 additional ENP common units. The net proceeds from ENP s issuance of common units was approximately $193.5 million, after deducting the underwriters

ENCORE ACQUISITION COMPANY

discount and a structuring fee of approximately $14.9 million, in the aggregate, and offering expenses of approximately $4.7 million.

On June 29, 2007, we completed the sale of certain oil and natural gas properties in the Mid-Continent area, primarily in the Anadarko and Arkoma fields of Oklahoma. In July 2007, additional Mid-Continent properties that were subject to preferential rights were sold. We 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.

On December 27, 2007, we entered into a purchase and investment agreement with ENP, which provided for the sale of certain oil and natural gas producing properties and related assets in the Permian and Williston Basins to ENP. The transaction closed on February 7, 2008, but was effective as of January 1, 2008. The consideration for the sale consisted of approximately $125.4 million in cash and 6,884,776 common units representing limited partner interests in ENP. To fund the cash portion of the sales price, ENP borrowed under its revolving credit facility. As of February 20, 2008, we owned 20,924,055 of ENP s outstanding common units, representing a 67.3 percent limited partner interest. Through our indirect ownership of ENP s general partner, we also hold 504,851 general partner units, representing a 1.6 percent general partner interest in ENP.

Financial Information About 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 segment to revenues and operating income (loss), and the identifiable assets attributable to each segment, are set forth in Note 17 of Notes to Consolidated Financial Statements included in Item 8. Financial Statements and Supplementary Data .

Proved Reserves. Our estimated total proved reserves at December 31, 2007 were 189 MMbls of oil and 256 Bcf of natural gas, based on December 31, 2007 spot market prices of $96.01 per Bbl for oil and $7.47 per Mcf for natural gas. On a BOE basis, our proved reserves were 231 MMBOE at December 31, 2007.

Most Valuable Asset. The CCA represented approximately 50 percent of our total proved reserves as of December 31, 2007 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 through primary, secondary, and tertiary recovery techniques.

Drilling. In 2007, we drilled 94 gross (67.3 net) operated productive wells and participated in drilling another 134 gross (15.2 net) non-operated productive wells for a total of 228 gross (82.5 net) productive wells. Also in 2007, we drilled 5 gross (3.2 net) operated non-productive wells and participated in drilling another 5 gross (2.7 net) non-operated non-productive wells for a total of 10 gross (5.9 net) non-productive wells. We invested $367.6 million in development and exploration activities in 2007, of which $14.7 million related to exploratory dry holes.

Table of Contents

ENCORE ACQUISITION COMPANY

Oil and Natural Gas Reserve Replacement. During 2007, we added 60.0 MMBOE of oil and natural gas reserves to our existing proved reserve base, which replaced 443 percent of the 13.5 MMBOE we produced in 2007. Our average reserve replacement for the three years ended December 31, 2007 was 322 percent. The following table sets forth the calculation of our reserve replacement for the periods indicated:

	Year Ended December 31,			Three-Year
	2007	2006	2005	Average
	(In MBOE, except percentages)			
Acquisition Reserve Replacement:				
Changes in Proved Reserves:				
Acquisitions of minerals-in-place	43,146	64	14,796	19,335
Divided by:				
Production	13,539	11,244	10,381	11,721
Acquisition Reserve Replacement	318%	1%	142%	165%
Development Reserve Replacement:				
Changes in Proved Reserves:				
Extensions, discoveries, and improved recovery	15,983	27,504	19,158	20,882
Revisions of estimates	896	(7,461)	(928)	(2,498)
Total development program	16,879	20,043	18,230	18,384
Divided by:				
Production	13,539	11,244	10,381	11,721
Development Reserve Replacement	125%	178%	176%	157%
Total Reserve Replacement:				
Changes in Proved Reserves:				
Acquisitions of minerals-in-place	43,146	64	14,796	19,335
Extensions, discoveries, and improved recovery	15,983	27,504	19,158	20,882
Revisions of estimates	896	(7,461)	(928)	(2,498)
Total reserve additions	60,025	20,107	33,026	37,719
Divided by:				
Production	13,539	11,244	10,381	11,721
Total Reserve Replacement	443%	179%	318%	322%

During the three years ended December 31, 2007, we invested $1.1 billion in acquiring proved oil and natural gas properties and leasehold acreage and $1.0 billion on development, exploitation, and exploration of these and our other properties.

Given the inherent decline of reserves resulting from production, we must more than offset produced volumes with new reserves in order to grow. Management uses reserve replacement as an indicator of our ability to replenish annual production volumes and grow our reserves. Management believes that reserve replacement is relevant and useful information as it is commonly used to evaluate the performance and prospects of entities engaged in the production and sale of depleting natural resources. It should be noted that reserve replacement is a statistical indicator that has limitations. As an annual measure, reserve replacement is limited because it typically varies widely based on the extent and timing of new discoveries and property acquisitions. The predictive and comparative value of reserve replacement is also limited for the same reasons. In addition, since reserve replacement does not consider the cost or timing of future production of new reserves, it cannot be used as a measure of value creation. Reserve replacement does not distinguish between changes in reserve quantities that are developed and those that will require additional time and funding to develop.

ENCORE ACQUISITION COMPANY

Business Strategy

Our primary business objective is to maximize shareholder value by growing our asset base, prudently investing internally generated cash flows, efficiently operating our properties, and maximizing long-term profitability. Our strategy for achieving this objective is to:

Maintain an active development program to maximize existing reserves and production. Our technological expertise, combined with our proficient field operations and reservoir engineering, has allowed us to increase production and reserves on our properties through infill, offset, and re-entry drilling, workovers, and recompletions. Our plan is to maintain an inventory of exploitation and development projects that provide a good source of future production.

Utilize enhanced oil recovery techniques to maximize existing reserves and production. We budget a portion of internally generated cash flows for secondary and tertiary recovery projects, including HPAI, that are longer-term in nature to increase production and proved reserves on our properties. In the CCA, we have successfully used HPAI techniques to increase our production. Throughout our Williston and Permian Basin properties, we have successfully used waterfloods to increase production. On certain of our non-operated properties in the Rockies, a tertiary recovery technique that uses carbon dioxide instead of water is being used successfully. Throughout our Bell Creek properties, we have initiated a polymer injection program. We believe that these enhanced oil recovery projects will continue to be a source of reserve and production growth.

Expand our reserves, production, and development inventory through a disciplined acquisition program. Using our experience, we have developed and refined an acquisition program designed to increase our reserves and complement our core properties. We have a staff of engineering and geoscience professionals who manage our core properties and use their experience and expertise to target and evaluate attractive acquisition opportunities. Following an acquisition, our technical professionals seek to enhance the value of the new assets through a proven development and exploitation program. We will continue to evaluate acquisition opportunities with the same disciplined commitment to acquire assets that fit our existing portfolio of properties and create value for our shareholders.

Explore for reserves. With the current commodity price environment, we believe exploration programs can provide a rate of return comparable to property acquisitions in certain areas. We seek to acquire undeveloped acreage and/or enter into development arrangements to explore in areas that complement our existing portfolio of properties. Successful exploration projects would expand our existing fields and could set up multi-well exploitation projects in the future.

Operate in a cost effective, efficient, and safe manner. As of December 31, 2007, we operated properties representing approximately 86 percent of our proved reserves, which allows us to control capital allocation, operate in a safe manner, and control timing of investments.

Challenges to Implementing Our Strategy. We face a number of challenges to implementing our strategy and achieving our goals. One challenge is to generate superior rates of return on our investments in a volatile commodity pricing environment, while replenishing our development inventory. Changing commodity prices and increased costs of goods and services affect the rate of return on property acquisitions, and the amount of our internally generated cash flows, and, in turn, can affect our capital budget. In addition to commodity price risk, we face strong competition from other independents and major oil and natural gas companies. Our views and the views of our competitors about future commodity prices affect our success in acquiring properties and the expected rate of return on each acquisition. For more information on the challenges to implementing our strategy and achieving our goals, please read Item 1A. Risk Factors below.

Operations

As of December 31, 2007, we operated properties representing approximately 86 percent of our proved reserves. As the operator, we are able to better control expenses, capital allocation, and the timing of

ENCORE ACQUISITION COMPANY

exploitation and development activities on our properties. We also own working interests in properties that are operated by third parties, and are required to pay our share of LOE, exploitation, and development costs. Please read Properties Nature of Our Ownership Interests below. During 2007, 2006, and 2005, our costs for development activities on non-operated properties were approximately $67.0 million, $50.2 million, and $28.2 million, respectively. We also own royalty interests in wells operated by third parties that are not burdened by LOE or capital costs; however, we have little or no control over the implementation of projects on these properties.

Production and Price History

The following table sets forth information regarding our net production volumes, average realized prices, including the effects of commodity derivative contracts, and average costs per BOE for the periods indicated:

	Year Ended December 31,		
	2007	**2006**	**2005**
Total Production Volumes:			
Oil (MBbls)	9,545	7,335	6,871
Natural gas (MMcf)	23,963	23,456	21,059
Combined (MBOE)	13,539	11,244	10,381
Average Daily Production Volumes:			
Oil (Bbls/D)	26,152	20,096	18,826
Natural gas (Mcf/D)	65,651	64,262	57,696
Combined (BOE/D)	37,094	30,807	28,442
Average Realized Prices:			
Oil (per Bbl)	$ 58.96	$ 47.30	$ 44.82
Natural gas (per Mcf)	6.26	6.24	7.09
Combined (per BOE)	52.66	43.87	44.05
Average Costs per BOE:			
Lease operations expense	$ 10.59	$ 8.73	$ 6.72
Production, ad valorem, and severance taxes	5.51	4.43	4.39
Depletion, depreciation, and amortization	13.59	10.09	8.25
Exploration	2.05	2.71	1.39
Derivative fair value loss (gain)	8.31	(2.17)	0.51
General and administrative	2.89	2.06	1.67
Provision for doubtful accounts	0.43	0.18	0.02
Other operating expense	1.26	0.71	0.89
Marketing loss (gain)	(0.11)	0.09	

Table of Contents

ENCORE ACQUISITION COMPANY

Productive Wells

The following table sets forth information relating to productive wells in which we owned a working interest at December 31, 2007. Wells are classified as oil or natural gas wells according to their predominant production stream. Gross wells are the total number of productive wells in which we have an interest, and net wells are determined by multiplying gross wells by our average working interest. As of December 31, 2007, we owned a working interest in 5,545 gross wells. 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	759	674	89%	17	4	26%
Permian Basin	1,985	774	39%	568	272	48%
Rockies	1,379	817	59%	61	44	72%
Mid-Continent	230	138	60%	546	145	27%
Total	4,353	2,403	55%	1,192	465	39%

(a) Our total wells include 3,056 operated wells and 2,489 non-operated wells. At December 31, 2007, 58 of our wells had multiple completions.

Table of Contents

ENCORE ACQUISITION COMPANY

Acreage

The following table sets forth information relating to our leasehold acreage at December 31, 2007. 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, 2007, our undeveloped acreage in the Rockies represents 60 percent of our total net undeveloped acreage. Our current leases expire at various dates between 2008 and 2029, with leases representing $6.2 million of cost set to expire in 2008 if not developed.

	Gross Acreage	Net Acreage
CCA:		
Developed	129,853	117,763
Undeveloped	143,706	112,944
	273,559	230,707
Permian Basin:		
Developed	63,814	39,025
Undeveloped	15,634	14,655
	79,448	53,680
Rockies:		
Developed	225,290	141,213
Undeveloped	650,054	452,875
	875,344	594,088
Mid-Continent:		
Developed	63,214	39,189
Undeveloped	273,815	179,163
	337,029	218,352
Total:		
Developed	482,171	337,190
Undeveloped	1,083,209	759,637
	1,565,380	1,096,827

Table of Contents

ENCORE ACQUISITION COMPANY

Drilling Results

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

	Year Ended December 31,					
	2007		2006		2005	
	Gross	Net	Gross	Net	Gross	Net
Development Wells:						
Productive	165	62	182	72	242	145
Dry holes	5	3	4	3	4	2
	170	65	186	75	246	147
Exploratory Wells:						
Productive	63	21	71	19	34	22
Dry holes	5	3	14	8	47	42
	68	24	85	27	81	64
Total:						
Productive	228	83	253	91	276	167
Dry holes	10	6	18	11	51	44
	238	89	271	102	327	211

Present Activities

As of December 31, 2007, we had a total of 14 gross (6.2 net) wells that had begun drilling and were in varying stages of drilling operations, of which 5 gross (2.3 net) were development wells. Also as of December 31, 2007, there were 33 gross (11.9 net) wells that had reached total depth and were in varying stages of completion pending first production, of which 15 gross (6.7 net) were development wells.

Delivery Commitments and Marketing

Our oil and natural gas production is principally sold to end users, marketers, refiners, and other purchasers that have access to nearby pipeline 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. While we typically market our oil and natural gas production for a term of one year or less, we have entered into an agreement to sell at least 4,500 Bbls/D at a floating market price through 2009.

For 2007, our largest purchaser was Eighty-Eight Oil, which accounted for approximately 14 percent of our total sales volumes. 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.

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

The difference between quoted NYMEX market prices and the price received at the wellhead for oil and natural gas production is commonly referred to as a differential. We expect the differential between the NYMEX price of crude oil and the wellhead price we receive to remain approximately constant in the first quarter of 2008 as compared to the $13.06 per Bbl differential we realized in the fourth quarter of 2007. In recent years, production increases from competing Canadian and Rocky Mountain producers, in conjunction with limited refining and pipeline capacity from the Rocky Mountain area, have gradually widened this differential. Natural gas differentials are expected to remain approximately constant or to widen slightly in the first quarter of 2008 as compared to the $0.55 per Mcf differential we realized in the fourth quarter of 2007. We cannot accurately predict future crude oil and natural gas differentials. Increases in the differential between the NYMEX price for oil and natural gas and the wellhead price we receive could have a material adverse effect on our results of operations, financial position, and cash flows.

Competition

The oil and natural gas industry is highly competitive. We encounter strong competition from other independents and major oil and natural gas companies in acquiring properties, contracting for development equipment, and securing trained personnel. Many of these competitors have financial, technical, and personnel 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. In the past, 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.

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 expensive pollution control equipment;
- 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;

ENCORE ACQUISITION COMPANY

- 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, 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 currently 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.

We currently 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

Table of Contents

ENCORE ACQUISITION COMPANY

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 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. Due to the significant level of uncertainty associated with the known and unknown environmental liabilities at the gas plant, ENP s estimates include a large contingency. ENP does not anticipate ceasing operations at the Elk Basin natural gas processing plant in the near future and do not anticipate a need to commence remedial activities at this time. However, a regulatory agency could require ENP to begin to investigate and remediate any contamination even while the gas plant remains in operation. As of December 31, 2007, ENP has recorded $4.4 million as future abandonment cost for decommissioning the Elk Basin natural gas processing plant, and ENP expects to continue reserving additional amounts based on its estimated timing to cease operations of the natural gas processing plant. Due to the significant level of 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. In addition to the future abandonment liability recorded for the Elk Basin plant, ENP has recorded an estimated liability of $1.0 million as of December 31, 2007 related to required environmental plant compliance costs.

In connection with ENP s IPO, we agreed to indemnify ENP through September 17, 2008 against certain potential environmental claims, losses, and expenses associated with the operation of ENP s assets in the Permian and Elk Basins. Our maximum liability for this indemnification obligation will not exceed $10 million. We will not have any obligation under this indemnification obligation until ENP s aggregate losses exceed $500,000, and then only to the extent such aggregate losses exceed $500,000. We have no indemnification obligations with respect to environmental matters for claims made as a result of changes in environmental laws promulgated after September 17, 2007.

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 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

ENCORE ACQUISITION COMPANY

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.

Recent 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 Earth s atmosphere. In response to such studies, the U.S. Congress is actively considering legislation to reduce emissions of greenhouse gases. In addition, at least 14 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 U.S. 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 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 comment. All of our current exploration and production activities, as well as proposed exploration and development plans, on federal lands require governmental permits that are subject to the requirements of NEPA. This process has the potential to delay the development of 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

12

Table of Contents

ENCORE ACQUISITION COMPANY

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 current 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 2007, and, as of the date of this Report, we are not aware of any environmental issues or claims that will require material capital expenditures during 2008. 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, we cannot assure you that the passage of more stringent laws or regulations in the future will not 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 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:

- the location of wells;
- the method of developing and casing wells;
- the surface use and restoration of properties upon which wells are drilled;
- the plugging and abandoning of wells; and
- notice to 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 to 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

ENCORE ACQUISITION COMPANY

imposes a production or severance tax with respect to the production and sale of oil, natural gas, and NGLs within its jurisdiction.

Interstate Crude Oil Transportation. ENP s Clearfork crude oil pipeline is an interstate common carrier pipeline, which is subject to regulation by the Federal Energy Regulatory Commission (the FERC) under the October 1977 version of the Interstate Commerce Act (ICA), and the Energy Policy Act of 1992 (EP Act 1992). ICA and its implementing regulations give the FERC authority to regulate the rates ENP charges for service on that interstate common carrier pipeline and generally require the rates and practices of interstate oil pipelines to be just and reasonable and nondiscriminatory. ICA also requires ENP to maintain tariffs on file with the FERC that set forth the rates ENP charges for providing transportation services on its interstate common carrier liquids pipeline as well as the rules and regulations governing these services. Shippers may protest, and the FERC may investigate, the lawfulness of new or changed tariff rates. The FERC can suspend those tariff rates for up to seven months. It can also require refunds of amounts collected pursuant to rates that are ultimately found to be unlawful. The FERC and interested parties can also challenge tariff rates that have become final and effective. EP Act 1992 deemed certain rates in effect prior to its passage to be just and reasonable and limited the circumstances under which a complaint can be made against such grandfathered rates. EP Act 1992 and its implementing regulations also allow interstate common carrier oil pipelines to annually index their rates up to a prescribed ceiling level. In addition, the FERC retains cost-of-service ratemaking, market-based rates, and settlement rates as alternatives to the indexing approach.

Natural Gas Gathering. Section 1(b) of the Natural Gas Act (NGA), exempts natural gas gathering facilities from the jurisdiction of 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 now that 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. ENP s gathering operations could be adversely affected should they become subject to the application of state or federal regulation of rates and services. ENP s 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 ENP s 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 currently 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.

Table of Contents

ENCORE ACQUISITION COMPANY

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 the NGA to prohibit market manipulation and also amended the NGA, and the Natural Gas Policy Act of 1978 (NGPA), to increase civil and criminal penalties for any violations of the NGA, NGPA, and any rules, regulations, or orders of the FERC to up to $1,000,000 per day, per violation. In addition, the FERC issued a final rule effective January 26, 2006 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 final rule works together with the FERC s enhanced penalty authority to provide increased oversight of the natural gas marketplace.

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 may apply to certain types of wells and production methods.

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 may 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 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

We had a staff of 364 persons, including 39 engineers, 16 geologists, and 15 landmen as of December 31, 2007, 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.

Table of Contents

ENCORE ACQUISITION COMPANY

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 the SEC s Public Reference Room at 100 F Street, NE, Washington, D.C. 20549. The public may obtain information on the operation of the Public Reference Room by calling the SEC at 1-800-SEC-0330. The SEC also maintains a website (www.sec.gov) that contains reports, proxy and information 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 and financial officers. 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 New York Stock Exchange (the NYSE) require us to disclose, we intend to disclose these events on our website.

We have filed the required certifications under Section 302 of the Sarbanes-Oxley Act of 2002 as Exhibits 31.1 and 31.2 to this Report. In 2007, we submitted to the NYSE the CEO certification required by Section 303A.12(a) of the NYSE s Listed Company Manual. In 2008, we expect to submit this certification to the NYSE after our annual meeting of stockholders.

Our board of directors (the Board) currently has four standing committees: (i) audit, (ii) compensation, (iii) nominating and corporate governance, and (iv) special stock award. The charters of our audit, compensation, and nominating and corporate governance committees are available on our website. Copies of our code of business conduct and ethics and Board committee charters are also available in print upon written request to: Corporate Secretary, Encore Acquisition Company, 777 Main Street, Suite 1400, Fort Worth, Texas 76102.

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

Properties

Nature of Our Ownership Interests

The following table sets forth the net production, proved reserve quantities, and PV-10 values of our properties by principal area of operation as of and for the periods indicated:

	2007 Net Production				Proved Reserve Quantities at December 31, 2007				PV-10 at December 31, 2007	
	Oil	Natural Gas	Total	Percent	Oil	Natural Gas	Total	Percent	Amount (a)	Percen
	(MBbls)	(MMcf)	(MBOE)		(MBbls)	(MMcf)	(MBOE)		(In thousands)	
CA	4,426	1,122	4,614	34%	113,519	14,763	115,979	50%	$ 2,074,429	46%

rmian Basin	1,214	8,937	2,703	20%	24,678	133,427	46,916	20%	828,921	19%
ockies	3,434	1,368	3,662	27%	47,842	18,499	50,925	22%	1,305,723	29%
id-Continent	471	12,536	2,560	19%	2,548	89,758	17,508	8%	259,446	6%
otal	9,545	23,963	13,539	100%	188,587	256,447	231,328	100%	$ 4,468,519	100%

(a) Giving effect to commodity derivative contracts, our PV-10 would have been decreased by $13.4 million at December 31, 2007. Standardized Measure at December 31, 2007 was $3.3 billion. Standardized Measure differs from PV-10 by $1.2 billion because Standardized Measure includes the effects of 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 feel PV-10 provides the best method for assessing the relative value of each of our areas.

ENCORE ACQUISITION COMPANY

The estimates of our proved oil and natural gas reserves are based on estimates prepared by Miller and Lents, Ltd. (Miller and Lents), independent petroleum engineers. Guidelines established by the SEC regarding the present value of future net revenues were used to prepare these reserve estimates. Oil and natural gas reserve engineering is 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 in this Report. 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 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.

During 2007, we filed estimates of oil and natural gas reserves as of December 31, 2006 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.

CCA Properties Montana and North Dakota

Our initial purchase of interests in the CCA was in 1999, and we have subsequently acquired additional working interests from various owners. As of December 31, 2007, we operated virtually all of our CCA properties with an average working interest of approximately 89 percent in the oil wells and 26 percent in the natural gas wells. The average daily production from our CCA properties during 2007 was 12,640 BOE/D.

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

ENCORE ACQUISITION COMPANY

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 a combination of waterfloods and HPAI. Since taking over operations, our net production from the CCA has increased by approximately 55 percent from 7,807 BOE/D (average for June 1999) to 12,080 BOE/D (average for the fourth quarter of 2007). We have accomplished ongoing production growth through a combination of:

- acquisition of additional interests;
- effective management of the existing wellbores;
- the addition of strategically positioned new horizontal and vertical wellbores;
- re-entry horizontal drilling using existing wellbores;
- waterflood enhancements; and
- implementation of our HPAI program.

In 2007, we drilled 20 gross wells in the CCA, of which 13 were horizontal re-entry wells that (i) reestablished production from non-producing wells, (ii) added additional production to existing producing wells, or (iii) served as injection wells for secondary and tertiary recovery projects. Including our HPAI project, we invested $41.6 million, $103.9 million, and $121.7 million in capital projects in the CCA during 2007, 2006, and 2005, respectively.

We plan to continue the development of the reserve base using the same strategies that gave rise to our past success in this area.

The CCA represents approximately 50 percent of our total proved reserves as of December 31, 2007 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 through primary, secondary, and tertiary recovery techniques.

In 2006, we began implementation of two improved waterfloods in the CCA: one in South Pine Unit in the Red River U4 and one in the Coral Creek Unit in the Red River U4. In 2007, both units showed initial response for the waterflood. We believe these projects have added significant reserves in the Red River U4 and expect to see meaningful production uplift in 2008.

HPAI. In 2002, we initiated a HPAI project on the CCA that injects air into the Red River U4 zone. The Red River U4 zone is the same zone where HPAI has been successfully implemented by other operators in adjacent areas on the CCA. We have seen positive results from this HPAI project at the Pennel and Little Beaver units.

We are currently injecting 55 MMcf/D of high pressure air in the Pennel and Little Beaver Units. The units are responding to the air injection with an increase of approximately 900 BOE/D over the expected production decline prior to the initiation of the project.

We believe that much of our acreage in the CCA has potential opportunities for utilizing HPAI recovery techniques at economic rates of return. We continue to evaluate and perform engineering studies on these projects. Over the next several years, we plan to study, engineer, and implement these development projects initially in the Red River U4 zone of the CCA. Additionally, we have other zones in the CCA that currently produce oil and may provide additional HPAI opportunities.

ENCORE ACQUISITION COMPANY

NPI. A major portion of our acreage position in the CCA is subject to NPI ranging from one percent to 50 percent. The holders of these NPIs 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 NPIs are deducted from our reserves and production data, and our revenues are reported net of NPI payments. The reserves and production attributed to NPIs are calculated by dividing estimated future NPI payments (in the case of reserves) or prior period actual NPI payments (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 NPIs and will have an inverse effect on our reported reserves and production. For 2007, 2006, and 2005, we reduced revenue for NPI payments by $32.5 million, $23.4 million, and $21.2 million, respectively.

Permian Basin Properties West Texas and New Mexico

West Texas

Our West Texas properties include seventeen 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. Production from the southern portion of the Permian Basin comes mainly from the Canyon, Devonian, Ellenberger, and Strawn formations with multiple pay intervals.

Average daily production for our West Texas properties increased approximately 27 percent from 5,626 BOE/D in the fourth quarter of 2006 to 7,122 BOE/D in the fourth quarter of 2007. We believe these properties will be an area of growth over the next several years. During 2007, we drilled 66 gross wells and invested approximately $120.8 million of capital to develop these properties.

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 will have the opportunity to develop approximately 100,000 gross acres. We will earn 30 percent of ExxonMobil s working interest and 22.5 percent of ExxonMobil s net revenue interest in each well drilled. We will operate each well during the drilling and completion phase, after which ExxonMobil will assume operational control of the well.

We will earn the right to participate in all fields by drilling a total of 24 commitment wells. During the commitment phase, ExxonMobil will have the option to receive non-recourse advanced funds from us attributable to ExxonMobil s 70 percent working interest in each commitment well. Once a commitment well is producing, ExxonMobil will repay 95 percent of the advanced funds plus accrued interest assessed on the unpaid balance through our monthly receipt of proceeds of oil and natural gas sales. As an alternative to receiving advanced funds during the commitment phase, ExxonMobil can elect to pay their share of capital costs for each well. After we have fulfilled our obligations under the commitment phase, we will be entitled to a 30 percent working interest in future drilling locations. We will have the right to propose and drill wells for as long as we are engaged in continuous drilling operations. As of December 31, 2007, we had 6 wells to drill, at a minimum cost of $1.0 million per well, in order to fulfill our commitment under the joint development agreement.

Table of Contents

ENCORE ACQUISITION COMPANY

In 2008, we intend to drill approximately 39 wells, including the 6 remaining commitment wells, and invest approximately $121.0 million of net capital in the development areas. We anticipate operating 5 rigs in West Texas by the end of 2008.

On December 27, 2007, we entered into a purchase and investment agreement with ENP, which provided for the sale of certain oil and natural gas producing properties and related assets in the Permian Basin to ENP. The transaction closed on February 7, 2008, but was effective as of January 1, 2008.

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. We expect to grow reserves in our New Mexico properties through:

- joint development agreements;
- agreements with major oil and natural gas companies;
- drill-to-earn agreements;
- farm-outs of close-in exploitation opportunities; and
- establishing built-in partnerships with other independent exploration companies.

Since May 2006, we have acquired or farmed-in approximately 10,500 gross acres and identified and secured approximately 30 low-risk infill locations.

Average daily production for these properties increased approximately 314 percent from 1,884 Mcfe/D in the fourth quarter of 2006 to 7,793 Mcfe/D in the fourth quarter of 2007. We believe these properties will be an area of growth over the next several years. During 2007, we drilled 4 operated wells, participated in 8 non-operated wells, and invested approximately $20.3 million of capital to develop these properties.

In 2008, we expect to increase production in New Mexico through conventional infill drilling opportunities.

Mid-Continent Properties Oklahoma, Arkansas, East Texas, Kansas, and North Louisiana

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 eastern Arkansas.

As previously discussed, during 2007, we disposed of certain properties in the Anadarko and Arkoma fields. As a result, our average daily production for these properties decreased approximately 72 percent from 30,430 Mcfe/D in the fourth quarter of 2006 to 8,555 Mcfe/D for the fourth quarter of 2007. During 2007, we drilled 61 gross wells and invested $60.4 million of development and exploration capital in these properties.

North Louisiana Salt Basin and East Texas Basin

The North Louisiana Salt Basin and East Texas Basin properties consist of operated working interests, non-operated working interests, and undeveloped leases acquired primarily in the Elm Grove and Overton acquisitions in 2004 and grassroot development in the Stockman and Danville field in east Texas. Our interests acquired in the Elm Grove acquisition are located in the Elm Grove Field in Bossier Parish, Louisiana, and include non-operated working interests ranging from one percent to 47 percent across 1,800 net acres in 15 sections.

ENCORE ACQUISITION COMPANY

The 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 between 8,000 and 11,500 feet.

During 2007, we drilled 54 gross wells and invested approximately $59.4 million of capital to develop these properties. Average daily production for these properties decreased five percent from 21,092 Mcfe/D in the fourth quarter of 2006 to 20,038 Mcfe/D for the fourth quarter of 2007. We drilled 6 operated wells in the Stockman and Danville fields. Production from our Stockman field increased from 740 Mcfe/D in the fourth quarter of 2006 to 3,027 Mcfe/D for the fourth quarter of 2007.

Rockies Properties   Montana, North Dakota, Wyoming, and Utah

Big Horn Basin   Montana and Wyoming

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 was formed by the Big Horn Mountains to the east, the Absaroka Mountains to the west, the Owl Creek Mountains to the south, and the Ny-Bowler Lineament to the north. The Big Horn Basin is located in Park County, Wyoming and Carbon County, Montana. The Big Horn Basin is characterized by oil and natural gas fields with long production histories and multiple producing formations.

ENP also owns and operates (i) the Elk Basin natural gas processing plant near Powell, Wyoming, (ii) the Clearfork crude oil pipeline extending from the South Elk Basin Field to the Elk Basin Field in Wyoming, (iii) 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 (iv) a small 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 was 4,255 BOE/D in the fourth quarter of 2007. During 2007, ENP drilled 6 gross wells and invested approximately $3.9 million of capital to develop these properties.

Williston Basin   Montana and North Dakota

Our Williston Basin properties have historically consisted of working and overriding royalty interests in several geographically concentrated fields. The properties are located in the Williston Basin in western North Dakota and eastern Montana, near our CCA properties. In April 2007, we acquired additional properties in the Williston Basin comprised of 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 134,000 acres. We had one rig drilling on the Bakken acreage in 2007.

Average daily production for these properties increased from 978 BOE/D in the fourth quarter of 2006 to 6,363 BOE/D in the fourth quarter of 2007, largely due to the acquisition of additional interests in April 2007. During 2007, we drilled 19 gross wells and invested approximately $42.7 million of capital to develop these properties.

On December 27, 2007, we entered into a purchase and investment agreement with ENP, which provided for the sale of certain oil and natural gas producing properties and related assets in the Williston Basin to ENP. The transaction closed on February 7, 2008, but was effective as of January 1, 2008.

Bell Creek Montana

Our Bell Creek properties are located in the Powder River Basin of southeastern Montana. We operate seven production units that comprise the Bell Creek properties, each with a 100 percent working interest. The shallow (less than 5,000 feet) Cretaceous-aged Muddy Sandstone reservoir produces oil. We have initiated a

ENCORE ACQUISITION COMPANY

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. Initial encouraging results on the producing wells have resulted in an expansion of the program in 2008.

We invested $6.6 million of capital to develop these properties in 2007. Average daily production from these properties more than doubled from 453 BOE/D in the fourth quarter of 2006 to 958 BOE/D in the fourth quarter of 2007.

Paradox Basin Utah

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 both operated by Resolute Natural Resources Company. In 2007, the operator continued the implementation of a tertiary project in 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 decreased approximately two percent from 704 BOE/D in the fourth quarter of 2006 to 688 BOE/D in the fourth quarter of 2007. During 2007, we invested approximately $9.5 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, NPIs, and other burdens under oil and natural gas leases;
- contractual obligations, including, in some cases, development obligations arising under joint operating agreements, farmout 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 indicated under Net Profits Interests above, a major portion of our acreage position in the CCA, our primary asset, is subject to NPIs.

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.

ITEM 1A. *RISK FACTORS*

Please carefully consider the following factors together with all of the other information included in this Report. If any of the following risks and uncertainties were actually to occur, our business, financial condition, or results of operations could be materially adversely affected. In that case, the trading price of our common stock could decline and an investor could lose all or part of his/her investment.

ENCORE ACQUISITION COMPANY

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

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

- domestic and foreign supply of and demand for oil and natural gas;
- weather conditions;
- overall domestic and global economic conditions;
- political and economic conditions in oil and natural gas producing countries, including those in the Middle East and South America;
- actions of the Organization of Petroleum Exporting Countries and other state-controlled oil companies relating to oil price and production controls;
- impact of the U.S. dollar exchange rates on oil and natural gas prices;
- technological advances affecting energy consumption and energy supply;
- armed conflicts in oil and natural gas producing regions;
- 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.

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 and repayment of indebtedness; and
- limit our ability to borrow money or raise additional capital.

An increase in the differential between the NYMEX or other benchmark prices of oil and natural gas and the wellhead price we receive could significantly 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, that are used for calculating commodity derivative settlements. The difference between the benchmark price and the price we receive is called a differential. We cannot accurately predict oil and natural gas differentials. In recent years, production increases from competing Canadian and Rocky Mountain producers, in conjunction with limited refining and pipeline capacity from the Rocky Mountain area, have gradually widened this differential. Increases in the differential between the benchmark price for oil and natural gas and the wellhead price we receive could significantly reduce our cash available for development of our properties and adversely affect our financial condition. For information

Table of Contents

ENCORE ACQUISITION COMPANY

regarding our expected differentials for 2008, please read Item 7. Management s Discussion and Analysis of 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. Oil and natural gas reserve engineering requires subjective estimates of underground accumulations of oil and natural gas and assumptions concerning future oil and natural gas prices, future production levels, and operating and development costs. In estimating our level of oil and natural gas reserves, we and our independent reserve engineers make certain assumptions that may prove to be incorrect, including assumptions relating to the level of oil and natural gas prices, future 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 classifications 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, 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. 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 Standardized Measure of our estimated proved reserves is not necessarily the same as the current market value of our estimated proved oil and natural gas 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.

The timing of both our production and our incurrence of expenses in connection with the development and production 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 in compliance with the Financial Accounting Standards Board s (FASB) Statement of Financial Accounting Standards (SFAS) No. 69, *Disclosures about Oil and Gas Producing Activities* , may not be the most appropriate discount factor based on interest rates in effect from time to time and risks associated with us or the oil and natural gas industry in general.

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

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 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.

Because our oil and natural gas properties are a depleting asset, we will 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

ENCORE ACQUISITION COMPANY

revolving credit facility, we may be unable to expend the capital necessary to find, develop, or acquire additional reserves.

The results of HPAI techniques are uncertain.

We utilize HPAI techniques on some of our properties and plan to use the techniques in the future on a portion of our properties, including our CCA properties. The additional production and reserves attributable to our use of HPAI techniques, if any, are inherently difficult to predict. If our HPAI programs do not allow for the extraction of residual hydrocarbons in the manner or to the extent that we anticipate, or the cost of implementing these techniques increases beyond our expectations, our future results of operations and financial condition could be materially adversely affected.

Future 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 adjustments to our estimated proved 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. If we incur such impairment charges in the future, 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.

If we do not make acquisitions on economically acceptable terms, our future growth will 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.

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. Competition for acquisitions is intense and may increase the cost of, or cause us to refrain from, completing acquisitions.

The failure to properly manage growth through acquisitions could adversely affect our results of operations.

Growing through acquisitions and managing that growth will require us to continue to invest in operational, financial, and management information systems and to attract, retain, motivate, and effectively manage our employees. Pursuing and integrating acquisitions involves a number of risks, including:

- diversion of management attention from existing operations;

unexpected losses of key employees, customers, and suppliers of the acquired business;

conforming the financial, technological, and management standards, processes, procedures, and controls of the acquired business with those of our existing operations; and

increasing the scope, geographic diversity, and complexity of our operations.

ENCORE ACQUISITION COMPANY

The process of integrating acquired operations into our existing operations may result in unforeseen operating difficulties and may require significant management attention and financial resources that would otherwise be available for the ongoing development or expansion of existing operations.

Any acquisitions we complete are subject to substantial risks that would 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 expenses and 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 to finance acquisitions;
- a significant increase in our interest expense or financial leverage if we incur additional debt to finance acquisitions;
- 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 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 assess fully 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 50 percent of our proved reserves as of December 31, 2007 and 34 percent of our 2007 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.

ENCORE ACQUISITION COMPANY

Our commodity derivative contract activities could result in financial losses or could reduce our income.

To reduce our exposure to adverse fluctuations in the prices of oil and natural gas, we currently and may in the future enter into derivative arrangements for a significant portion of our oil and natural gas production that could result in commodity derivative losses. The extent of our commodity price exposure is related largely to the effectiveness and scope of our derivative activities. For example, the derivative instruments we utilize are based on posted market prices, which may differ significantly from the actual crude oil, natural gas, and NGL prices we realize in our operations.

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; 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.

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

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

Other companies operated approximately 14 percent of our properties (measured by total reserves) and approximately 45 percent of our wells as of December 31, 2007. 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.

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 in prospects that we pursue 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 wells, 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

ENCORE ACQUISITION COMPANY

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.

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. 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:

- high 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 results of operations.

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

Approximately 65 percent of our production and 75 percent of our reserves rely on secondary and tertiary recovery techniques, which include waterfloods and injecting natural gases into producing formations to

ENCORE ACQUISITION COMPANY

enhance hydrocarbon recovery. If production response is less than forecast for a particular project, then the project may be uneconomic or 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 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.

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 terrorist attacks and hurricanes 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.

Terrorist activities and the potential for military and other actions could adversely affect our business.

The threat of terrorism and the impact of military and other action have caused instability in world financial markets and could lead to increased volatility in prices for oil and natural gas, all of which could adversely affect the markets for our production. Future acts of terrorism could be directed against companies operating in the United States. The U.S. government has issued public warnings that indicate that energy assets might be specific targets of terrorist organizations. These developments have subjected our operations to increased risk and, depending on their ultimate magnitude, could have a material adverse effect on our business.

Table of Contents

ENCORE ACQUISITION COMPANY

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. For example, our Board recently approved a $445 million capital budget for 2008, excluding acquisitions. We intend to finance these capital expenditures through a combination operating cash flows and external financing arrangements. 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.

Shortages of rigs, equipment and crews could delay our operations and reduce our cash available for distribution.

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 currently have planned. Any delay in the development of new wells or a significant increase in development costs could reduce our revenues.

The loss of key personnel could adversely affect our business.

We depend to a large extent on the efforts and continued employment of I. Jon Brumley, our Chairman of the Board, Jon S. Brumley, our Chief Executive Officer and President, and other key personnel. The loss of the services of any of these persons could adversely affect our business, and we do not have employment agreements with, and do not maintain key person insurance on the lives of, any of these persons.

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.

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 contracted 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.

ENCORE ACQUISITION COMPANY

Competition in the oil and natural gas industry is intense, and many of our competitors have greater financial, technological, and other 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 and employ financial, technical, and personnel resources substantially greater than ours. Those companies may be able to develop and acquire more prospects and productive properties than our financial or personnel resources permit. Our ability to acquire additional properties and to discover reserves in the future will depend on our ability to evaluate and select suitable properties and to consummate transactions in a highly competitive environment. Many of our larger 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 financial or human resources permit. In addition, there is substantial competition for investment capital in the oil and natural gas industry. These larger 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 with larger companies could have a material adverse impact on our business activities, financial condition and results of operations.

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 Regulations 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.

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, 2007, we had total debt of $1.1 billion and $371.5 million of available borrowing capacity under our revolving credit facility.

We have the ability to incur additional debt under our revolving credit facility, subject to borrowing base limitations of our revolving credit facility. 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 be impaired or such financing may not be available on favorable terms;

ENCORE ACQUISITION COMPANY

covenants contained in our existing and future debt arrangements will 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, a downturn in our business, or the economy generally, than our competitors with less debt.

Our ability to service our indebtedness will depend upon, among other things, our future financial and operating performance, which will be 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 current or future 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.

ITEM 1B. ***UNRESOLVED STAFF COMMENTS***

There were no unresolved SEC staff comments as of December 31, 2007.

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 results of operations or financial position.

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

There were no matters submitted to stockholders during the fourth quarter of 2007.

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, $0.01 par value, is listed on the NYSE under the symbol EAC . The following table sets forth high and low sales prices of our common stock for each quarterly period of 2007 and 2006:

	High	Low
2007		
Quarter ended December 31	$ 38.55	$ 30.59
Quarter ended September 30	$ 33.00	$ 25.79
Quarter ended June 30	$ 29.96	$ 24.21
Quarter ended March 31	$ 26.50	$ 21.74
2006		
Quarter ended December 31	$ 27.62	$ 22.45
Quarter ended September 30	$ 30.97	$ 22.63
Quarter ended June 30	$ 32.59	$ 22.75
Quarter ended March 31	$ 36.84	$ 28.16

On February 20, 2008, the closing sales price of our common stock as reported by the NYSE was $36.05 per share and we had approximately 406 shareholders of record. This number does not include owners for whom common stock may be held in street names.

Purchases of Equity Securities by the Issuer and Affiliated Purchasers

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

Month	Total Number of Shares Purchased	Average Price Paid per Share	Total Number of Shares Purchased as Part of Publicly Announced Plans or Programs	Approximate Dollar Value of Shares That May Yet Be Purchased Under the Plans or Programs
October		$		
November(a)	17,690	$ 33.34		
December		$		

Total	17,690	$ 33.34		$ 50,000,000

(a) During the fourth quarter of 2007, certain employees surrendered shares of common stock to pay income tax withholding obligations in conjunction with vesting of restricted shares.

In December 2007, we announced that the Board had approved a new share repurchase program authorizing the purchase of up to $50 million of our common stock. As of December 31, 2007, we had not repurchased any of our common shares under this program. As of February 25, 2008, we had repurchased approximately 844,191 shares of our outstanding common stock for approximately $27.2 million, or an average price of $32.23 per share.

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

ENCORE ACQUISITION COMPANY

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.

Stock Performance Graph

The following graph compares our cumulative total stockholder return during the period from January 1, 2003 to December 31, 2007 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, 2003 and that all dividends, if any, were reinvested. The following graph is being furnished pursuant to SEC rules. It 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, 2003 Among Encore Acquisition Company, the Standard & Poor s 500 Index, and the Independent Oil and Gas Index

Table of Contents

ENCORE ACQUISITION COMPANY

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

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,(h)				
	2007	2006	2005	2004	2003
	(In thousands, except per share and per unit data)				
Consolidated Statements of Operations Data:					
Revenues(a):					
Oil	$ 562,817	$ 346,974	$ 307,959	$ 220,649	$ 176,351
Natural gas	150,107	146,325	149,365	77,884	43,745
Marketing(e)	42,021	147,563			
Total revenues	$ 754,945	$ 640,862	$ 457,324	$ 298,533	$ 220,096
Net income	$ 17,155	$ 92,398	$ 103,425(b)	$ 82,147	$ 63,641(c)
Net income per common share(d):					
Basic	$ 0.32	$ 1.78	$ 2.12	$ 1.74	$ 1.41
Diluted	$ 0.32	$ 1.75	$ 2.09	$ 1.72	$ 1.40
Weighted average common shares outstanding(d):					
Basic	53,170	51,865	48,682	47,090	45,153
Diluted	54,144	52,736	49,522	47,738	45,500
Consolidated Statements of Cash Flows Data:					
Cash provided by (used in):					
Operating activities	$ 319,707	$ 297,333	$ 292,269	$ 171,821	$ 123,818
Investing activities	(929,556)	(397,430)	(573,560)	(433,470)	(153,747)
Financing activities	610,790	99,206	281,842	262,321	17,303
Total Production Volumes:					
Oil (Bbls)	9,545	7,335	6,871	6,679	6,601
Natural gas (Mcf)	23,963	23,456	21,059	14,089	9,051
Combined (BOE)	13,539	11,244	10,381	9,027	8,110
Average Realized Prices:					
Oil ($/Bbl)	$ 58.96	$ 47.30	$ 44.82	$ 33.04	$ 26.72
Natural gas ($/Mcf)	6.26	6.24	7.09	5.53	4.83
Combined ($/BOE)	52.66	43.87	44.05	33.07	27.14
Average Costs per BOE:					
Lease operations(f)	$ 10.59	$ 8.73	$ 6.72	$ 5.30	$ 4.70
	5.51	4.43	4.39	3.36	2.71

Production, ad valorem, and severance taxes					
Depletion, depreciation, and amortization	13.59	10.09	8.25	5.38	4.13
Exploration(f)	2.05	2.71	1.39	0.44	
General and administrative(f)	2.89	2.06	1.67	1.33	1.12
Derivative fair value loss (gain)(g)	8.31	(2.17)	0.51	0.56	(0.11)
Provision for doubtful accounts	0.43	0.18	0.02		
Other operating expense	1.26	0.71	0.89	0.56	0.43
Marketing loss (gain)(e)	(0.11)	0.09			

ENCORE ACQUISITION COMPANY

	As of December 31,				
	2007	2006	2005	2004	2003
			(In thousands)		
Proved Reserves:					
Oil (Bbls)	188,587	153,434	148,387	134,048	117,732
Natural gas (Mcf)	256,447	306,764	283,865	234,030	138,950
Combined (BOE)	231,328	204,561	195,698	173,053	140,890
Consolidated Balance Sheets Data:					
Working capital	$ (16,220)	$ (40,745)	$ (56,838)	$ (15,566)	$ (52)
Total assets	2,784,561	2,006,900	1,705,705	1,123,400	672,138
Total long-term debt	1,120,236	661,696	673,189	379,000	179,000
Stockholders equity	948,155	816,865	546,781	473,575	358,975

(a) For 2007, 2006, 2005, 2004, and 2003 we reduced oil and natural gas revenues for NPI payments by $32.5 million, $23.4 million, $21.2 million, $12.6 million, and $5.8 million, respectively.

(b) Net income for 2005 includes an after-tax loss on early redemption of debt of $12.2 million.

(c) Net income for 2003 includes $0.9 million income from the cumulative effect of accounting change, net of tax, related to the adoption of SFAS No. 143, *Accounting for Asset Retirement Obligations* .

(d) Net income per common share and weighted average common shares outstanding for 2004 and 2003 have been adjusted for the effects of the 3-for-2 stock split in July 2005.

(e) 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 purchasing oil from third party companies as market conditions changed and historical pipeline space was realized. Implementing this change in direction allowed us to focus on the marketing of our own equity production, leveraging newly gained pipeline space, and on delivering oil to various newly developed markets in an effort to maximize netback value to the wellhead. In March 2007, ENP acquired a natural gas pipeline from Anadarko as part of the Big Horn Basin 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.

(f) On January 1, 2006, we adopted the provisions of SFAS No. 123R, *Share-Based Payment* (SFAS 123R). Due to the adoption of SFAS 123R, non-cash equity-based compensation expense for 2005, 2004, and 2003 has been reclassified to allocate the amount to the same respective income statement lines as the respective employees cash compensation. This resulted in increases in LOE of $1.3 million, $0.7 million, and $0.2 million during 2005, 2004, and 2003, respectively, increases in general and administrative (G&A) expense of $2.6 million, $1.1 million, and $0.4 million during 2005, 2004, and 2003, respectively, and increases in exploration expense of $41 thousand and $29 thousand during 2005 and 2004, respectively.

(g) 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) .

(h) We acquired certain oil and natural gas properties and related assets in the Big Horn Basin and Williston Basins from Anadarko in March 2007 and April 2007, respectively. We disposed of certain oil and natural gas properties and related assets in the Mid-Continent in June 2007. We also acquired Crusader Energy Corporation (Crusader) in October 2005 and Cortez Oil & Gas, Inc. (Cortez) in April 2004.

Table of Contents

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 position and results of operations should be read in conjunction with our consolidated financial statements, the accompanying notes, and the supplemental oil and natural gas disclosures 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 stated 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 below and Item 1A. Risk Factors .

Introduction

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

- Overview of Business
- 2007 Highlights
- 2008 Outlook
- Results of Operations
  - Comparison of 2007 to 2006
  - Comparison of 2006 to 2005
- 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 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 enhanced oil recovery 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.

In February 2007, we formed ENP to acquire, exploit, and develop oil and natural gas properties and to acquire, own, and operate related assets. On September 17, 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 their over-allotment option to purchase 1,148,400 additional ENP common units. The net proceeds from ENP s

ENCORE ACQUISITION COMPANY

issuance of common units was 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. The net proceeds were used to repay in full $126.4 million of outstanding indebtedness, including accrued interest, under ENP s subordinated credit agreement with EAP Operating, Inc., an indirect wholly owned subsidiary of us, and $65.9 million of outstanding borrowings under its revolving credit facility. As of December 31, 2007, public unitholders in ENP had a limited partner interest of approximately 40.2 percent. We include ENP in our consolidated financial statements and show the ownership by the public as a minority interest.

On January 16, 2007, we entered into a purchase and sale agreement with certain subsidiaries of Anadarko to acquire oil and natural gas properties and related assets in the Big Horn Basin of Montana and Wyoming, 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. Prior to closing, we assigned the rights and duties under the purchase and sale agreement relating to the Elk Basin assets to OLLC. The closing of the Big Horn Basin acquisition occurred on March 7, 2007. The purchase price for the Big Horn Basin assets was approximately $393.6 million, including transaction costs of approximately $1.3 million.

On January 23, 2007, we entered into a purchase and sale agreement with certain subsidiaries of Anadarko to acquire oil and natural gas properties and related assets in the Williston Basin of Montana and Wyoming. The closing of the Williston Basin acquisition occurred on April 11, 2007. The purchase price for the Williston Basin assets was approximately $392.1 million, including transaction costs of approximately $1.3 million. The properties are comprised of 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.

As of December 31, 2006, estimated total proved reserves associated with the Big Horn Basin and Williston Basin acquisitions were 38,934 MBOE, 92 percent of which were oil and 90 percent of which were proved developed.

On June 29, 2007, we completed the sale of certain oil and natural gas properties in the Mid-Continent area. In July 2007, additional Mid-Continent properties that were subject to preferential rights were sold. We 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 net proceeds were used to reduce outstanding borrowings under our revolving credit facility. As of December 31, 2006, estimated total proved reserves associated with the Mid-Continent disposition were 17,416 MBOE, 92 percent of which were natural gas and 75 percent of which were proved developed.

On December 27, 2007, we entered into a purchase and investment agreement with ENP, which provided for the sale of certain oil and natural gas producing properties and related assets in the Permian and Williston Basins to ENP. The transaction closed on February 7, 2008, but was effective as of January 1, 2008. The consideration for the sale consisted of approximately $125.4 million in cash and 6,884,776 common units representing limited partner interests in ENP. To fund the cash portion of the sales price, ENP borrowed under its revolving credit facility. As of February 20, 2008, we owned 20,924,055 of ENP s outstanding common units, representing a 67.3 percent limited partner interest. Through our indirect ownership of ENP s general partner, we also hold 504,851 general partner units, representing a 1.6 percent general partner interest in ENP.

Our financial results and ability to generate cash depend upon many factors, particularly the price of oil and natural gas. Oil prices continued to strengthen in 2007, with average NYMEX prices increasing in each of the past three years. In addition, our oil wellhead differentials to NYMEX tightened in 2007 as we realized 88 percent of the average NYMEX oil price, as compared to 82 percent in 2006. Natural gas prices continued to deteriorate in 2007 from an all-time high in 2005, but average NYMEX prices remain higher than historical averages. However, our natural gas wellhead differentials to NYMEX improved in 2007 as we realized 98 percent of the average NYMEX natural gas price, as compared to 92 percent in 2006. Commodity prices

Table of Contents

ENCORE ACQUISITION COMPANY

are influenced by many factors that are outside of our control. We cannot accurately predict future commodity benchmark or wellhead 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 estimated future production.

We continue to believe that a portfolio of long-lived quality assets will position us for future success, and that reserve replacement is a key statistical measure of our success in growing our asset base. During 2007, we replaced 443 percent of our production. Our development program replaced 125 percent of our 2007 production and our acquisitions, primarily the Big Horn Basin and Williston Basin acquisitions, replaced 318 percent of our 2007 production. Please read Items 1 and 2. Business and Properties General Oil and Natural Gas Reserve Replacement for the calculation of our reserve replacement.

2007 Highlights

Our financial and operating results for 2007 included the following:

Oil and natural gas reserves as of December 31, 2007 increased 13 percent to 231 MMBOE from 205 MMBOE as of December 31, 2006. We added 60.0 MMBOE of reserves, replacing 443 percent of the 13.5 MMBOE we produced. At December 31, 2007, oil reserves accounted for 82 percent of total proved reserves and 68 percent of proved reserves were developed. The estimated PV-10 of our reserves as of December 31, 2007 increased by 128 percent to $4.5 billion (using a 10 percent discount rate and constant prices of $96.01 per Bbl of oil and $7.47 per Mcf of natural gas) from $2.0 billion as of December 31, 2006 (using a 10 percent discount rate and constant prices of $61.06 per Bbl of oil and $5.48 per Mcf of natural gas). Our Standardized Measure at December 31, 2007 was $3.3 billion, as compared to $1.5 billion at December 31, 2006. Standardized Measure differs from PV-10 because Standardized Measure includes the effect of future income taxes.

Our oil and natural gas revenues increased 45 percent to $712.9 million as compared to $493.3 million in 2006 as a result of increased production volumes and higher average realized prices.

Our average realized oil price, including the effects of commodity derivative contracts, increased $11.66 per Bbl to $58.96 per Bbl as compared to $47.30 per Bbl in 2006. Our average realized natural gas price, including the effects of commodity derivative contracts, remained virtually unchanged at $6.26 per Mcf as compared to $6.24 per Mcf in 2006.

Production volumes increased 20 percent to 37,094 BOE/D as compared to 30,807 BOE/D in 2006, primarily as a result of our Big Horn Basin and Williston Basin acquisitions and our development program. Oil represented 71 percent and 65 percent of our total production volumes in 2007 and 2006, respectively.

We invested $1.2 billion in oil and natural gas activities (excluding related asset retirement obligations of $8.4 million). Of this amount, we invested $367.5 million in development, exploitation, HPAI expansion, and exploration activities, which yielded 228 gross (82.5 net) productive wells, and $840.3 million on acquisitions, primarily related to our Big Horn Basin and Williston Basin acquisitions. We operated between 7 and 12 drilling rigs during 2007, including 4 to 6 rigs related to our West Texas joint development agreement with ExxonMobil.

On March 7, 2007, we completed the Big Horn Basin acquisition.

On April 11, 2007, we completed the Williston Basin acquisition.

On June 29, 2007, we completed the Mid-Continent disposition.

On September 17, 2007, ENP completed its IPO of 9,000,000 common units and on October 11, 2007, the underwriters exercised their over-allotment option to purchase 1,148,400 additional ENP common units.

Table of Contents

ENCORE ACQUISITION COMPANY

2008 Outlook

For 2008, the Board has approved the following $445 million capital budget for oil and natural gas related activities, excluding proved property acquisitions (in thousands):

Development and exploitation	$ 260,000
Exploration	166,000
Acquisitions of leasehold acreage	19,000
Total	$ 445,000

The prices we receive for our oil and natural gas production are largely based on current market prices, which are beyond our control. For comparability and accountability, we take a constant approach to budgeting commodity prices. We presently analyze our inventory of capital projects based on current NYMEX strip prices. If NYMEX prices trend downward for a sustained period of time, we may reevaluate our capital projects. If commodity prices are significantly lower than current NYMEX strip prices, it could have a material adverse effect on our results of operations in 2008. In this case, we would have to borrow additional money under our revolving credit facility, attempt to access the capital markets, or curtail our capital program. However, we currently believe that our 2008 capital budget will be within our anticipated operating cash flows as our current hedging program is expected to mitigate the effects of a significant decline in commodity prices. If development is curtailed or ended, future cash flows could be materially negatively impacted.

Table of Contents

ENCORE ACQUISITION COMPANY

Results of Operations

Comparison of 2007 to 2006

Oil and natural gas revenues and production. The following table illustrates the primary components of oil and natural gas revenues for 2007 and 2006, as well as each year s respective oil and natural gas production volumes and average prices:

	Year Ended December 31, 2007	Year Ended December 31, 2006	*Increase/ (Decrease)*	
Revenues (in thousands):				
Oil wellhead	$ 606,112	$ 399,180	*$ 206,932*	
Oil hedges	(43,295)	(52,206)	*8,911*	
Total oil revenues	$ 562,817	$ 346,974	*$ 215,843*	*62%*
Natural gas wellhead	$ 160,399	$ 154,458	*$ 5,941*	
Natural gas hedges	(10,292)	(8,133)	*(2,159)*	
Total natural gas revenues	$ 150,107	$ 146,325	*$ 3,782*	*3%*
Combined wellhead	$ 766,511	$ 553,638	*$ 212,873*	
Combined hedges	(53,587)	(60,339)	*6,752*	
Total combined oil and natural gas revenues	$ 712,924	$ 493,299	*$ 219,625*	*45%*
Average realized prices:				
Oil wellhead ($/Bbl)	$ 63.50	$ 54.42	*$ 9.08*	
Oil hedges ($/Bbl)	(4.54)	(7.12)	*2.58*	
Total oil revenues ($/Bbl)	$ 58.96	$ 47.30	*$ 11.66*	*25%*
Natural gas wellhead ($/Mcf)	$ 6.69	$ 6.59	*$ 0.10*	
Natural gas hedges ($/Mcf)	(0.43)	(0.35)	*(0.08)*	
Total natural gas revenues ($/Mcf)	$ 6.26	$ 6.24	*$ 0.02*	*0%*
Combined wellhead ($/BOE)	$ 56.62	$ 49.24	*$ 7.38*	
Combined hedges ($/BOE)	(3.96)	(5.37)	*1.41*	
Total combined oil and natural gas revenues ($/BOE)	$ 52.66	$ 43.87	*$ 8.79*	*20%*

Total production volumes:				
Oil (MBbls)	9,545	7,335	*2,210*	*30%*
Natural gas (MMcf)	23,963	23,456	*507*	*2%*
Combined (MBOE)	13,539	11,244	*2,295*	*20%*
Average daily production volumes:				
Oil (Bbl/D)	26,152	20,096	*6,056*	*30%*
Natural gas (Mcf/D)	65,651	64,262	*1,389*	*2%*
Combined (BOE/D)	37,094	30,807	*6,287*	*20%*
Average NYMEX prices:				
Oil (per Bbl)	$ 72.39	$ 66.22	*$ 6.17*	*9%*
Natural gas (per Mcf)	$ 6.86	$ 7.18	*$ (0.32)*	(4)%

Table of Contents

ENCORE ACQUISITION COMPANY

Oil revenues increased $215.8 million from $347.0 million in 2006 to $562.8 million in 2007. The increase was primarily due to an increase in oil production volumes of 2,210 MBbls, which contributed approximately $120.3 million in additional oil revenues. The increase in production volumes was the result of our Big Horn Basin and Williston Basin acquisitions and our development programs.

Our average realized oil price increased $11.66 per Bbl as a result of an increase in our wellhead price and a decrease in the effects of commodity derivative contracts included in oil revenues. Our higher average oil wellhead price increased oil revenues by $86.7 million, or $9.08 per Bbl, and the decrease in the effects of commodity derivative contracts, which were previously designated as hedges, increased oil revenues by $8.9 million, or $2.58 per Bbl. Our average oil wellhead price increased as a result of increases in the overall market price for oil, as reflected in the increase in the average NYMEX price from $66.22 per Bbl in 2006 to $72.39 per Bbl in 2007.

Our oil wellhead revenue was reduced by $31.9 million and $22.8 million in 2007 and 2006, respectively, for NPI payments related to our CCA properties.

Natural gas revenues increased $3.8 million from $146.3 million in 2006 to $150.1 million in 2007. The increase was primarily due to an increase in production volumes of 507 MMcf, which contributed approximately $3.3 million in additional natural gas revenues. The increase in natural gas production volumes was the result of our West Texas joint development agreement with ExxonMobil and our development program in the Mid-Continent area, partially offset by natural gas production sold in conjunction with our Mid-Continent disposition.

Our average realized natural gas price increased $0.02 per Mcf as a result of an increase in our wellhead price, partially offset by an increase in the effects of commodity derivative contracts included in natural gas revenues. Our higher average natural gas wellhead price increased natural gas revenues by $2.6 million, or $0.10 per Mcf, and the increase in the effects of commodity derivative contracts, which were previously designated as hedges, reduced natural gas revenues by $2.2 million, or $0.08 per Mcf. Our average natural gas wellhead price increased as a result of the tightening of our natural gas differential despite decreases in the overall market price for natural gas, as reflected in the decrease in the average NYMEX price from $7.18 per Mcf in 2006 to $6.86 per Mcf in 2007.

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

	Year Ended December 31, 2007	Year Ended December 31, 2006
Oil wellhead ($/Bbl)	$ 63.50	$ 54.42
Average NYMEX ($/Bbl)	$ 72.39	$ 66.22
Differential to NYMEX	$ (8.89)	$ (11.80)
Oil wellhead to NYMEX percentage	88%	82%
Natural gas wellhead ($/Mcf)	$ 6.69	$ 6.59
Average NYMEX ($/Mcf)	$ 6.86	$ 7.18
Differential to NYMEX	$ (0.17)	$ (0.59)
Natural gas wellhead to NYMEX percentage	98%	92%

Our oil wellhead price as a percentage of the average NYMEX price tightened to 88 percent in 2007 as compared to 82 percent in 2006. We expect our oil wellhead differentials to remain approximately constant in the first quarter of 2008 as compared to the $13.06 per Bbl differential we realized in the fourth quarter of 2007 due to continued production increases from competing Canadian and Rocky Mountain producers, limited refining and pipeline capacity in the Rocky Mountain area, and corresponding steep pricing discounts.

Table of Contents

ENCORE ACQUISITION COMPANY

Our natural gas wellhead price as a percentage of the average NYMEX price improved to 98 percent in 2007 as compared to 92 percent in 2006. The differential improved because of a higher MMBtu content of our natural gas and efforts to reduce natural gas transportation and gathering costs. We expect our natural gas wellhead differentials to remain approximately constant or to widen slightly in the first quarter of 2008 as compared to the $0.55 per Mcf differential we realized in the fourth quarter of 2007.

Marketing revenues and expenses. In 2006, we purchased third-party oil Bbls from counterparties 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 purchasing oil from third party companies as market conditions changed and historical pipeline space was realized. Implementing this change in direction allowed us to focus on the marketing of our own equity production, leveraging newly gained pipeline space, and on delivering oil to various newly developed markets in an effort to maximize netback value to the wellhead.

In March 2007, ENP acquired a natural gas pipeline from Anadarko as part of the Big Horn Basin 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.

The following table summarizes our marketing activities for 2007 and 2006:

	Year Ended December 31, 2007	2006
	(In thousands, except per BOE amounts)	
Marketing revenues	$ 42,021	$ 147,563
Marketing expenses	(40,549)	(148,571)
Marketing gain (loss)	$ 1,472	$ (1,008)
Marketing revenues per BOE	$ 3.10	$ 13.12
Marketing expenses per BOE	(2.99)	(13.21)
Marketing gain (loss), per BOE	$ 0.11	$ (0.09)

Table of Contents

ENCORE ACQUISITION COMPANY

Expenses. The following table summarizes our expenses, excluding marketing expenses shown above, for 2007 and 2006:

	Year Ended December 31, 2007	Year Ended December 31, 2006	*Increase/ (Decrease)*	
Expenses (in thousands):				
Production:				
Lease operations	$ 143,426	$ 98,194	*$ 45,232*	
Production, ad valorem, and severance taxes	74,585	49,780	*24,805*	
Total production expenses	218,011	147,974	*70,037*	*47%*
Other:				
Depletion, depreciation, and amortization	183,980	113,463	*70,517*	
Exploration	27,726	30,519	*(2,793)*	
General and administrative	39,124	23,194	*15,930*	
Derivative fair value loss (gain)	112,483	(24,388)	*136,871*	
Provision for doubtful accounts	5,816	1,970	*3,846*	
Other operating	17,066	8,053	*9,013*	
Total operating	604,206	300,785	*303,421*	*101%*
Interest	88,704	45,131	*43,573*	
Income tax provision	14,476	55,406	*(40,930)*	
Total expenses	$ 707,386	$ 401,322	*$ 306,064*	*76%*
Expenses (per BOE):				
Production:				
Lease operations	$ 10.59	$ 8.73	*$ 1.86*	
Production, ad valorem, and severance taxes	5.51	4.43	*1.08*	
Total production expenses	16.10	13.16	*2.94*	*22%*
Other:				
Depletion, depreciation, and amortization	13.59	10.09	*3.50*	
Exploration	2.05	2.71	*(0.66)*	
General and administrative	2.89	2.06	*0.83*	
Derivative fair value loss (gain)	8.31	(2.17)	*10.48*	
Provision for doubtful accounts	0.43	0.18	*0.25*	
Other operating	1.26	0.71	*0.55*	
Total operating	44.63	26.74	*17.89*	*67%*
Interest	6.55	4.01	*2.54*	
Income tax provision	1.07	4.93	*(3.86)*	

Total expenses	$	52.25	$	35.68	*$*	*16.57*	*46%*

Production expenses. Total production expenses increased $70.0 million from $148.0 million in 2006 to $218.0 million in 2007. This increase resulted from an increase in total production volumes, as well as a $2.94 increase in production expenses per BOE. Our production margin (defined as oil and natural gas revenues less production expenses) increased by $149.6 million (43 percent) to $494.9 million in 2007 as compared to $345.3 million in 2006. Total production expenses per BOE increased by 22 percent while total oil and natural

Table of Contents

ENCORE ACQUISITION COMPANY

gas revenues per BOE increased by only 20 percent. On a per BOE basis, our production margin increased 19 percent to $36.56 per BOE for 2007 as compared to $30.71 per BOE for 2006.

Production expense attributable to LOE increased $45.2 million from $98.2 million in 2006 to $143.4 million in 2007, primarily as a result of a $1.86 increase in the average per BOE rate, which contributed approximately $25.2 million of additional LOE, and an increase in production volumes, which contributed approximately $20.0 million of additional LOE. The increase in production volumes is primarily the result of our Big Horn Basin and Williston Basin acquisitions. The increase in our average LOE per BOE rate was attributable to:

increases in prices paid to oilfield service companies and suppliers;

increased operational activity to maximize production;

HPAI expenses at the CCA; and

higher salary levels for engineers and other technical professionals.

Production expense attributable to production, ad valorem, and severance taxes (production taxes) increased $24.8 million from $49.8 million in 2006 to $74.6 million in 2007. The increase is primarily due to higher wellhead revenues. As a percentage of oil and natural gas revenues (excluding the effects of commodity derivative contracts), production taxes increased to 9.7 percent in 2007 as compared to 9.0 percent in 2006 as a result of higher rates in the states where the properties associated with our Big Horn Basin and Williston Basin acquisitions are located. The effect of commodity derivative contracts is excluded from oil and natural gas revenues in the calculation of these percentages because this method more closely reflects the method used to calculate actual production taxes paid to taxing authorities.

Depletion, depreciation, and amortization (DD&A) expense. DD&A expense increased $70.5 million from $113.5 million in 2006 to $184.0 million in 2007 due to a $3.50 increase in the per BOE rate and increased production volumes. The per BOE rate increased due to the higher cost basis of the properties associated with our Big Horn Basin and Williston Basin acquisitions, development of proved undeveloped reserves, and higher finding, development, and acquisition costs resulting from increases in rig rates, oilfield services costs, and acquisition costs. These factors resulted in additional DD&A expense of approximately $47.3 million, while the increase in production volumes resulted in additional DD&A expense of approximately $23.2 million.

Exploration expense. Exploration expense decreased $2.8 million from $30.5 million in 2006 to $27.7 million in 2007. During 2007, we expensed 5 exploratory dry holes totaling $14.7 million. During 2006, we expensed 14 exploratory dry holes totaling $17.3 million. The following table details our exploration expenses for 2007 and 2006:

	Year Ended December 31, 2007	Year Ended December 31, 2006	*Increase/ (Decrease)*
	(In thousands)		
Dry holes	$ 14,673	$ 17,257	*$ (2,584)*
Geological and seismic	1,455	1,720	*(265)*

Delay rentals	784	670	*114*
Impairment of unproved acreage	10,814	10,872	*(58)*
Total	$ 27,726	$ 30,519	*$ (2,793)*

With the current commodity price environment, we believe exploration programs can provide a rate of return comparable to property acquisitions in certain areas. We seek to acquire undeveloped acreage and/or enter into drilling arrangements to explore in areas that complement our portfolio of properties. In keeping

ENCORE ACQUISITION COMPANY

with our exploitation focus, the exploration projects expand existing fields or could set up multi-well exploitation projects if successful.

G&A expense. G&A expense increased $15.9 million from $23.2 million in 2006 to $39.1 million in 2007, primarily due to $6.8 million of non-cash unit-based compensation expense related to ENP s management incentive units, increased staffing to manage our larger asset base, higher activity levels, and increased personnel costs due to intense competition for human resources within the industry.

Derivative fair value loss (gain). 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 has no effect on our cash flows, results of operations are affected by mark-to-market gains and losses, which fluctuate with the changes in oil and natural gas prices.

During 2007, we recorded a $112.5 million derivative fair value loss as compared to a $24.4 million derivative fair value gain in 2006, the components of which were as follows:

	Year Ended December 31, 2007	Year Ended December 31, 2006	*Increase/ (Decrease)*
	(In thousands)		
Ineffectiveness on designated cash flow hedges	$	$ 1,748	*$ (1,748)*
Mark-to-market loss (gain) on commodity derivative contracts	85,372	(31,205)	*116,577*
Premium amortization	41,051	13,926	*27,125*
Settlements on commodity derivative contracts	(13,940)	(8,857)	*(5,083)*
Total derivative fair value loss (gain)	$ 112,483	$ (24,388)	*$ 136,871*

Provision for doubtful accounts. Provision for doubtful accounts increased $3.8 million from $2.0 million in 2006 to $5.8 million in 2007. The increase is primarily due to an increase in the payout allowance related to the ExxonMobil joint development agreement.

Other operating expense. Other operating expense increased $9.0 million from $8.1 million in 2006 to $17.1 million in 2007. The increase is primarily due to a $7.4 million loss on the sale of certain Mid-Continent properties and increases in third-party transportation costs attributable to moving our CCA production into markets outside the immediate area of the production.

Interest expense. Interest expense increased $43.6 million from $45.1 million in 2006 to $88.7 million in 2007. The increase is primarily due to additional debt used to finance the Big Horn Basin and Williston Basin acquisitions. The weighted average interest rate for all long-term debt for 2007 was 6.9 percent as compared to 6.1 percent for 2006.

The following table illustrates the components of interest expense for 2007 and 2006:

	Year Ended December 31, 2007	Year Ended December 31, 2006	*Increase/ (Decrease)*
	(In thousands)		
6.25% Notes	$ 9,705	$ 9,684	*$ 21*
6.0% Notes	18,517	18,418	*99*
7.25% Notes	10,988	10,984	*4*
Revolving credit facilities	46,085	3,609	*42,476*
Other	3,409	2,436	*973*
Total	$ 88,704	$ 45,131	*$ 43,573*

ENCORE ACQUISITION COMPANY

Minority interest. As of December 31, 2007, public unitholders in ENP had a limited partner interest of approximately 40.2 percent. We include ENP in our consolidated financial statements and show the ownership by the public as a minority interest. The minority interest loss in ENP was $7.5 million for 2007.

Income taxes. During 2007, we recorded an income tax provision of $14.5 million as compared to $55.4 million in 2006. Our effective tax rate increased to 45.8 percent in 2007 as compared to 37.5 percent in 2006 primarily due to a permanent rate adjustment for ENP s management incentive units, a state rate adjustment due to larger apportionment of future taxable income to states with higher tax rates, and permanent timing adjustments that will not reverse in future periods.

Comparison of 2006 to 2005

Oil and natural gas revenues and production. The following table illustrates the primary components of oil and natural gas revenues for 2006 and 2005, as well as each year s respective oil and natural gas production volumes and average prices:

	Year Ended December 31, 2006	Year Ended December 31, 2005	*Increase/ (Decrease)*	
Revenues (in thousands):				
Oil wellhead	$ 399,180	$ 350,837	*$ 48,343*	
Oil hedges	(52,206)	(42,878)	*(9,328)*	
Total oil revenues	$ 346,974	$ 307,959	*$ 39,015*	*13%*
Natural gas wellhead	$ 154,458	$ 165,794	*$ (11,336)*	
Natural gas hedges	(8,133)	(16,429)	*8,296*	
Total natural gas revenues	$ 146,325	$ 149,365	*$ (3,040)*	(2)%
Combined wellhead	$ 553,638	$ 516,631	*$ 37,007*	
Combined hedges	(60,339)	(59,307)	*(1,032)*	
Total combined oil and natural gas revenues	$ 493,299	$ 457,324	*$ 35,975*	*8%*
Average realized prices:				
Oil wellhead ($/Bbl)	$ 54.42	$ 51.06	*$ 3.36*	
Oil hedges ($/Bbl)	(7.12)	(6.24)	*(0.88)*	
Total oil revenues ($/Bbl)	$ 47.30	$ 44.82	*$ 2.48*	*6%*
Natural gas wellhead ($/Mcf)	$ 6.59	$ 7.87	*$ (1.28)*	
Natural gas hedges ($/Mcf)	(0.35)	(0.78)	*0.43*	

Total natural gas revenues ($/Mcf)	$	6.24	$	7.09	*$*	*(0.85)*	(12)*%*
Combined wellhead ($/BOE)	$	49.24	$	49.76	*$*	*(0.52)*	
Combined hedges ($/BOE)		(5.37)		(5.71)		*0.34*	
Total combined oil and natural gas revenues ($/BOE)	$	43.87	$	44.05	*$*	*(0.18)*	*0%*
Total production volumes:							
Oil (MBbls)		7,335		6,871		*464*	*7%*
Natural gas (MMcf)		23,456		21,059		*2,397*	*11%*
Combined (MBOE)		11,244		10,381		*863*	*8%*

Table of Contents

ENCORE ACQUISITION COMPANY

	Year Ended December 31, 2006	Year Ended December 31, 2005	*Increase/ (Decrease)*	
Average daily production volumes:				
Oil (Bbl/D)	20,096	18,826	*1,270*	*7%*
Natural gas (Mcf/D)	64,262	57,696	*6,566*	*11%*
Combined (BOE/D)	30,807	28,442	*2,365*	*8%*
Average NYMEX prices:				
Oil (per Bbl)	$ 66.22	$ 56.56	*$ 9.66*	*17%*
Natural gas (per Mcf)	$ 7.18	$ 8.96	*$ (1.78)*	(20)%

Oil revenues increased $39.0 million from $308.0 million in 2005 to $347.0 million in 2006. The increase was due primarily to higher realized average oil prices, which contributed approximately $15.3 million in additional oil revenues, and an increase in oil production volumes of 464 MBbls, which contributed approximately $23.7 million in additional oil revenues. The increase in production volumes was the result of our development program and a full year of production on properties acquired during the second half of 2005. The increase in revenues attributable to higher realized average oil price consisted of an increase resulting from higher average wellhead oil price of $24.7 million, or $3.36 per Bbl, partially offset by an increased hedging charge of $9.3 million, or $0.88 per Bbl. Our average oil wellhead price increased $3.36 per Bbl in 2006 over 2005 as a result of increases in the overall market price for oil as reflected in the increase in the average NYMEX price from $56.56 per Bbl in 2005 to $66.22 per Bbl in 2006.

Our oil wellhead revenue was reduced by $22.8 million and $20.6 million in 2006 and 2005, respectively, for NPI payments related to our CCA properties.

Natural gas revenues decreased $3.0 million from $149.4 million in 2005 to $146.3 million in 2006. The decrease was primarily due to lower realized average natural gas prices, which reduced revenues by approximately $21.9 million, partially offset by increased natural gas production volumes of 2,397 MMcf, which contributed approximately $18.9 million in additional natural gas revenues. The decrease in revenues from lower realized average natural gas prices consisted of a decrease resulting from a lower average wellhead natural gas price of $30.2 million, $1.28 per Mcf, partially offset by a decreased hedging charge of $8.3 million, or $0.43 per Mcf. Our average natural gas wellhead price decreased $1.28 per Mcf in 2006 from 2005 due to a decrease in the overall market price of natural gas as reflected in the decrease in the average NYMEX price from $8.96 per Mcf in 2005 to $7.18 per Mcf in 2006. The increase in production volumes was the result of our development program and a full year of production on properties acquired during the second half of 2005.

The table below illustrates the relationship between oil and natural gas wellhead prices as a percentage of average NYMEX prices for 2006 and 2005. Management uses the wellhead to NYMEX margin analysis to analyze trends in our oil and natural gas revenues.

ENCORE ACQUISITION COMPANY

	Year Ended December 31, 2006	2005
Oil wellhead ($/Bbl)	$ 54.42	$ 51.06
Average NYMEX ($/Bbl)	$ 66.22	$ 56.56
Differential to NYMEX	$ (11.80)	$ (5.50)
Oil wellhead to NYMEX percentage	82%	90%
Natural gas wellhead ($/Mcf)	$ 6.59	$ 7.87
Average NYMEX ($/Mcf)	$ 7.18	$ 8.96
Differential to NYMEX	$ (0.59)	$ (1.09)
Natural gas wellhead to NYMEX percentage	92%	88%

In the first quarter of 2006, our oil wellhead price as a percentage of the average NYMEX price decreased to as low as 65 percent. The widening of the differential was due to market conditions in the Rocky Mountain refining area, which has adversely affected the oil wellhead price we receive on our CCA and Williston Basin production. Production increases from competing Canadian and Rocky Mountain producers, in conjunction with limited refining and pipeline capacity in the Rocky Mountain area, created steep pricing discounts in the first quarter of 2006. These discounts narrowed in the remainder of 2006, though they were still higher than our historical average. The increase in the oil differential in 2006 as compared to 2005 adversely impacted oil revenues by $46.2 million. As Rocky Mountain refiners completed maintenance and increased their demand for crude oil, our oil wellhead price as a percentage of the average NYMEX price improved from the first quarter of 2006 throughout the remainder of 2006, but still remained wider than our historical average.

In the fourth quarter of 2006, our natural gas wellhead price as a percentage of the average NYMEX price percentage increased to as high as 100 percent. This favorable variance was due to our natural gas production in the North Louisiana Salt Basin and Crockett County, Texas, which was sold at Katy, Houston Ship Channel, and Henry Hub natural gas prices, which were higher than the average front-month NYMEX natural gas price. The increase in the natural gas differential percentage favorably impacted natural gas revenues by $16.2 million in 2006 as compared with 2005.

Marketing revenues and expenses. In 2006, we purchased third-party oil Bbls from counterparties 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. Prior to 2006, marketing activities were not material. The following table summarizes our marketing activities for 2006 (in thousands, except per BOE amounts):

Marketing revenues	$ 147,563
Marketing expenses	(148,571)
Marketing loss	$ (1,008)

Marketing revenues per BOE	$	13.12
Marketing expenses per BOE		(13.21)
Marketing loss per BOE	$	(0.09)

Expenses. On January 1, 2006, we adopted the provisions of SFAS 123R, which requires entities to recognize in their financial statements the cost of employee services received in exchange for awards of equity instruments based on the grant date fair value of those awards. As a result, in 2006, we recognized expense associated with stock options which previously were only presented in pro forma disclosures. Total non-cash

ENCORE ACQUISITION COMPANY

equity-based compensation expense in 2006, consisting of expense associated with both restricted stock and stock options, was $9.0 million. This amount is not reported separately on our Consolidated Statements of Operations but is allocated to LOE, exploration, and G&A expense based on the allocation of the respective employees cash compensation.

The following table summarizes our expenses, excluding marketing expenses shown above, for 2006 and 2005:

	Year Ended December 31, 2006	Year Ended December 31, 2005	*Increase/ (Decrease)*	
Expenses (in thousands):				
Production:				
Lease operations	$ 98,194	$ 69,744	*$ 28,450*	
Production, ad valorem, and severance taxes	49,780	45,601	*4,179*	
Total production expenses	147,974	115,345	*32,629*	*28%*
Other:				
Depletion, depreciation, and amortization	113,463	85,627	*27,836*	
Exploration	30,519	14,443	*16,076*	
General and administrative	23,194	17,268	*5,926*	
Derivative fair value loss (gain)	(24,388)	5,290	*(29,678)*	
Loss on early redemption of debt		19,477	*(19,477)*	
Provision for doubtful accounts	1,970	231	*1,739*	
Other operating	8,053	9,254	*(1,201)*	
Total operating	300,785	266,935	*33,850*	*13%*
Interest	45,131	34,055	*11,076*	
Income tax provision	55,406	53,948	*1,458*	
Total expenses	$ 401,322	$ 354,938	*$ 46,384*	*13%*
Expenses (per BOE):				
Production:				
Lease operations	$ 8.73	$ 6.72	*$ 2.01*	
Production, ad valorem, and severance taxes	4.43	4.39	*0.04*	
Total production expenses	13.16	11.11	*2.05*	*18%*
Other:				
Depletion, depreciation, and amortization	10.09	8.25	*1.84*	
Exploration	2.71	1.39	*1.32*	
General and administrative	2.06	1.67	*0.39*	
Derivative fair value loss (gain)	(2.17)	0.51	*(2.68)*	
Loss on early redemption of debt		1.88	*(1.88)*	
Provision for doubtful accounts	0.18	0.02	*0.16*	

Other operating		0.71		0.89	*(0.18)*	
Total operating		26.74		25.72	*1.02*	*4%*
Interest		4.01		3.28	*0.73*	
Income tax provision		4.93		5.20	*(0.27)*	
Total expenses	$	35.68	$	34.20	*$ 1.48*	*4%*

Production expenses. Total production expenses increased $32.6 million from $115.3 million in 2005 to $148.0 million in 2006. This increase resulted from an increase in total production volumes, as well as a $2.05

ENCORE ACQUISITION COMPANY

increase in production expenses per BOE. Total production expenses per BOE increased by 18 percent while total oil and natural gas revenues per BOE remained virtually unchanged. As a result of these changes, our production margin for 2006 decreased seven percent to $30.71 per BOE as compared to $32.94 per BOE for 2005.

Production expense attributable to LOE for 2006 increased $28.5 million from $69.7 million in 2005 to $98.2 million in 2006. The increase was due to higher production volumes, which contributed approximately $5.8 million of additional LOE, and a $2.01 increase in the average per BOE rate, which contributed approximately $22.7 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 due to the higher price environment;
- increased operational activity to maximize production;
- the operation of wells with higher operating costs (which offered acceptable rates of return due to increases in oil and natural gas prices);
- higher than expected operating costs in the Anadarko Basin and Arkoma Basin of Oklahoma and the North Louisiana Salt Basin;
- higher salary levels for engineers and other technical professionals;
- expensing HPAI costs associated with the Little Beaver Phase 2 program; and
- increased equity-based compensation expense attributable to equity instruments granted to employees.

Prior to the adoption of SFAS 123R, non-cash equity-based compensation expense was separately reported on the accompanying Consolidated Statements of Operations. Due to the adoption of SFAS 123R, non-cash equity-based compensation expense in 2005 was reclassified to allocate the amount to the same respective income statement lines as the respective employees cash compensation. As all full-time employees, including field personnel, are eligible for equity grants under our long-term incentive plan, LOE, G&A expense, and exploration expense were changed to reflect the new presentation. This change resulted in additional LOE of $2.4 million in 2006, or $0.22 per BOE, as compared to $1.3 million in 2005, or $0.13 per BOE. The increase in non-cash equity-based compensation expense allocated to LOE was primarily due to equity instruments granted to employees in 2006 and expensing of stock options beginning January 1, 2006 in accordance with SFAS 123R.

Production expense attributable to production taxes increased $4.2 million from $45.6 million in 2005 to $49.8 million in 2006. The increase was due to higher production volumes, which contributed approximately $3.8 million of additional production taxes. As a percentage of oil and natural gas revenues (excluding the effects of hedges), production taxes remained constant at approximately nine percent in 2006 and 2005.

DD&A expense. DD&A expense increased $27.8 million from $85.6 million in 2005 to $113.5 million in 2006 due to a higher per BOE rate and increased production volumes. The per BOE rate in 2006 increased $1.84 as compared to 2005 due to development of previously undeveloped reserves and higher finding, development, and acquisition costs, which were a result of increases in rig rates, oilfield services costs, and acquisition costs. These factors resulted in additional DD&A expense of approximately $20.7 million. The increase in production volumes resulted in approximately $7.1 million of additional DD&A expense.

Exploration expense. Exploration expense increased $16.1 million in 2006 as compared to 2005. During 2006, we expensed 14 exploratory dry holes totaling $17.3 million. During 2005, we expensed 47 exploratory dry holes totaling $8.6 million. In addition, impairment of unproved acreage in 2006 increased $8.8 million as we added $24.5 million in additional leasehold costs, expanded our exploratory drilling efforts, and recorded a

Table of Contents

ENCORE ACQUISITION COMPANY

$4.5 million write-down to the cost of unproved acreage in the shallow gas area of Montana based on drilling results in the area. The following table details our exploration expenses for 2006 and 2005:

	Year Ended December 31, 2006	Year Ended December 31, 2005	*Increase/ (Decrease)*
	(In thousands)		
Dry holes	$ 17,257	$ 8,632	*$ 8,625*
Geological and seismic	1,720	3,137	*(1,417)*
Delay rentals	670	635	*35*
Impairment of unproved acreage	10,872	2,039	*8,833*
Total	$ 30,519	$ 14,443	*$ 16,076*

G&A expense. G&A expense increased $5.9 million from $17.3 million in 2005 to $23.2 million in 2006. The overall increase, as well as the $0.39 increase in the per BOE rate, was primarily the result of increased equity-based compensation expense attributable to equity instruments granted to employees.

The previously discussed adoption of SFAS 123R and change in presentation of non-cash equity-based compensation expense resulted in additional G&A expense of $6.5 million in 2006, or $0.58 per BOE, as compared to $2.6 million in 2005, or $0.25 per BOE. The increase in non-cash equity-based compensation expense allocated to G&A expense was primarily due to equity instruments granted to employees in 2006 and expensing of stock options beginning January 1, 2006 in accordance with SFAS 123R.

Derivative fair value loss (gain). During 2006, we recorded a $24.4 million derivative fair value gain as compared to a $5.3 million loss in 2005, the components of which were as follows:

	Year Ended December 31, 2006	Year Ended December 31, 2005	*Increase/ (Decrease)*
	(In thousands)		
Ineffectiveness on designated cash flow hedges	$ 1,748	$ 8,371	*$ (6,623)*
Mark-to-market loss (gain):			
Interest rate swap		462	*(462)*
Commodity derivative contracts	(31,205)	(10,539)	*(20,666)*
Premium amortization	13,926	8,489	*5,437*
Settlements:			
Interest rate swap		(312)	*312*
Commodity derivative contracts	(8,857)	(1,181)	*(7,676)*
Total derivative fair value loss (gain)	$ (24,388)	$ 5,290	*$ (29,678)*

Loss on early redemption of debt. In 2005, we recorded a one-time $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 (the 83/8% Notes). We redeemed all $150 million of the 83/8% Notes with proceeds received from the issuance of our $300 million of 6.0% Senior Subordinated Notes (the 6.0% Notes).

Interest expense. Interest expense increased $11.1 million in 2006 as compared to 2005. The increase was primarily due to additional debt used to finance acquisitions and our capital program. We issued $150 million of 7.25% Senior Subordinated Notes (the 7.25% Notes) in November 2005, $300 million of 6.0% Notes in July 2005, and $150 million of 6.25% Senior Subordinated Notes (the 6.25% Notes) in April 2004. We also redeemed all $150 million of 83/8% Notes in August 2005. The weighted average interest rate for all long-term indebtedness, net of hedges, for 2006 was 6.1 percent as compared to 6.8 percent for 2005.

ENCORE ACQUISITION COMPANY

The following table illustrates the components of interest expense for 2006 and 2005:

	Year Ended December 31, 2006	Year Ended December 31, 2005	*Increase/ (Decrease)*
	(In thousands)		
83/8% Notes	$	$ 8,079	*$ (8,079)*
6.25% Notes	9,684	9,657	*27*
6.0% Notes	18,418	8,675	*9,743*
7.25% Notes	10,984	1,153	*9,831*
Revolving credit facility	3,609	5,834	*(2,225)*
Other	2,436	657	*1,779*
Total	$ 45,131	$ 34,055	*$ 11,076*

Income taxes. Income tax expense for 2006 increased $1.5 million over 2005. This was due to higher pre-tax income and an increase in our effective tax rate. Our effective tax rate increased in 2006 to 37.5 percent from 34.3 percent in 2005 due to the absence of Section 43 income tax credits during 2006 and changes to the Texas franchise tax. The Enhanced Oil Recovery credits available under Section 43 were fully phased out beginning in the 2006 tax year due to high oil prices in 2005. Therefore, no credits were generated during 2006. We were able to reduce our income tax provision in 2005 by $3.2 million by using Section 43 credits. In addition, a Texas franchise tax reform measure that was signed into law in May 2006 caused us to adjust our net deferred tax balances using the new higher marginal tax rate we expect to be effective when those deferred taxes reverse. This resulted in a charge of $1.1 million during 2006. The Texas margin tax was offset by an overall reduction in the income tax rate of states other than Texas due to higher sales in low or no tax states.

Capital Commitments, Capital Resources, and Liquidity

Capital commitments. Our primary needs for cash are:

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

Acquisitions of oil and natural gas properties and leasehold acreage;

Funding of necessary working capital; and

Contractual obligations.

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

	Year Ended December 31,		
	2007	2006	2005
	(In thousands)		
Development and exploitation	$ 265,744	$ 228,014	$ 236,467
Exploration	97,453	95,205	57,046
HPAI	4,272	25,470	32,053
Total	$ 367,469	$ 348,689	$ 325,566

Our expenditures for development and exploitation activities primarily relate to drilling development and infill wells, workovers of existing wells, and field related facilities. Our development and exploitation capital for 2007 yielded a total of 165 gross (61.7 net) successful wells and 5 gross (3.3 net) development dry holes.

ENCORE ACQUISITION COMPANY

Our expenditures for exploration investments primarily relate to drilling exploratory wells, seismic costs, delay rentals, and geological and geophysical costs. Our exploration capital for 2007 yielded 63 gross (20.9 net) successful wells and 5 gross (2.6 net) exploratory dry holes.

We currently have 9 operated rigs drilling on the onshore continental United States with 2 rigs in the Mid-Continent, 1 rig in the Northern area, 1 rig in the New Mexico area, and 5 rigs in West Texas.

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

	Year Ended December 31,		
	2007	2006	2005
	(In thousands)		
Acquisitions of proved property	$ 787,988	$ 4,486	$ 224,469
Acquisitions of leasehold acreage	52,306	24,462	21,205
Total	$ 840,294	$ 28,948	$ 245,674

On March 7, 2007, we acquired oil and natural gas properties in the Big Horn Basin, including the Elk Basin field and the Gooseberry field. ENP paid approximately $330.7 million, including transaction costs of approximately $1.1 million, for the Elk Basin field and we paid $62.9 million, including transaction costs of approximately $0.2 million, for the Gooseberry field. On April 11, 2007, we acquired oil and natural gas properties in the Williston Basin for approximately $392.1 million, including transaction costs of approximately $1.3 million. The total purchase price of these acquisitions allocated to proved properties was $779.5 million.

On October 14, 2005, we completed the acquisition of Crusader for a purchase price of approximately $109.6 million, which includes acquired working capital. The acquired properties were located primarily in the western Anadarko Basin and the Golden Trend area of Oklahoma. On November 30, 2005, we acquired certain oil and natural gas properties in West Texas and western Oklahoma from Kerr-McGee Corporation for a purchase price of approximately $101.4 million. On September 8, 2005, we acquired certain oil and natural gas properties in the Williston Basin for a purchase price of approximately $28.6 million. In addition to these acquisitions, we invested approximately $12.2 million during 2005 to acquire additional working interests in various areas.

During 2007, 2006, and 2005, our capital expenditures for leasehold acreage costs totaled $52.3 million, $24.5 million, and $21.2 million, respectively. During 2007, $16.1 million related to the Williston Basin acquisition and the remainder related to the acquisition of unproved acreage in various areas. Leasehold costs incurred in 2006 related to the acquisition of unproved acreage in various areas. Leasehold costs incurred in 2005 consist primarily of $14.3 million to acquire undeveloped leasehold costs in various areas and $6.9 million to acquire leases in the Crusader acquisition.

Funding of necessary working capital. Our working capital (defined as total current assets less total current liabilities) was negative $16.2 million, negative $40.7 million, and negative $56.8 million at December 31, 2007, 2006, and

2005, respectively. The improvement in 2007 as compared to 2006 was primarily attributable to an increase in accounts receivable as a result of increased oil and natural gas sales, partially offset by an increase in the NYMEX price of oil, which negatively impacted the fair value of outstanding derivative contracts. The improvement in 2006 as compared to 2005 was primarily attributable to decreases in the NYMEX price of natural gas, which favorably impacted the fair value of outstanding derivative contracts, partially offset by the decrease in accounts receivable from sales of natural gas resulting from the lower price.

For 2008, we expect working capital to remain negative. Negative working capital is expected mainly due to fair values of our commodity derivative contracts (the settlements of which will be offset by cash flows

ENCORE ACQUISITION COMPANY

from the sale of production mitigated against price risk under those contracts) and deferred commodity derivative contract premiums. We anticipate cash reserves to be close to zero because we intend to use any excess cash to fund capital obligations and pay down any outstanding borrowings under our revolving credit facility. We do not plan to pay cash dividends in the foreseeable future. In 2008, 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. Assuming relatively stable commodity prices and constant or increasing production volumes, our operating cash flow should remain positive in 2008.

The Board has approved a capital budget of $445 million for 2008. The level of these and other future expenditures is largely discretionary, and the amount of funds devoted to any particular activity may increase or decrease significantly, depending on available opportunities, timing of projects, and market conditions. We plan to finance our ongoing expenditures using internally generated cash flow and borrowings under our revolving credit facility.

Off-balance sheet arrangements. We do not have any investments in unconsolidated entities or persons that could materially affect our liquidity or the availability of capital resources. Other than those described below under Contractual Obligations and undrawn letters of credit related to our revolving credit facilities, we do not have any off-balance sheet arrangements that are material to our financial position or results of operations.

Contractual obligations. The following table illustrates our contractual obligations and commercial commitments outstanding at December 31, 2007:

Contractual Obligations and Commitments	Total	Payments Due by Period 2008	2009-2010 (In thousands)	2011-2012	Thereafter
6.25% Notes(a)	$ 210,938	$ 9,375	$ 18,750	$ 18,750	$ 164,063
6.0% Notes(a)	444,000	18,000	36,000	36,000	354,000
7.25% Notes(a)	258,750	10,875	21,750	21,750	204,375
Revolving credit facilities(a)	696,052	32,913	65,827	65,827	531,485
Derivative obligations(b)	67,781	32,075	35,706		
Development commitments(c)	102,640	93,291	9,349		
Operating leases and commitments(d)	18,583	3,712	6,507	5,757	2,607
Asset retirement obligations(e)	156,008	2,379	2,275	2,275	149,079
Total	$ 1,954,752	$ 202,620	$ 196,164	$ 150,359	$ 1,405,609

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

(b) Derivative obligations represent net liabilities for commodity derivative contracts that were valued as of December 31, 2007. With the exception of $51.9 million of deferred premiums on commodity derivative contracts, the ultimate settlement of our remaining derivative obligations are unknown because they are subject to continuing market risk. Please read Item 7A. Quantitative and Qualitative Disclosures about Market Risk and Note 13 of Notes to Consolidated Financial Statements included in Item 8. Financial Statements and Supplementary Data for additional information regarding our derivative obligations.

(c) Development commitments include: authorized purchases for work in process of $50.9 million; future minimum payments for drilling rig operations of $45.7 million; and $6.0 million for minimum capital obligations associated with the remaining 6 commitment wells to be drilled under the ExxonMobil joint development agreement. Also at December 31, 2007, we had $203.9 million of authorized purchases not

Table of Contents

ENCORE ACQUISITION COMPANY

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.

(d) Operating leases and commitments include office space and equipment obligations that have non-cancelable lease terms in excess of one year of $17.2 million and future minimum payments for other operating commitments of $1.4 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.

(e) Asset retirement obligations represent the undiscounted future plugging and abandonment expenses on oil and natural gas properties and related facilities disposal at the completion of field life. Please read Note 5 of Notes to Consolidated Financial Statements included in Item 8. Financial Statements and Supplementary Data for additional information regarding our asset retirement obligations.

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

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

We expect the differential between the NYMEX price of crude oil and the wellhead price we receive to remain approximately constant in the first quarter of 2008 as compared to the $13.06 per Bbl differential we realized in the fourth quarter of 2007. In recent years, production increases from competing Canadian and Rocky Mountain producers, in conjunction with limited refining and pipeline capacity from the Rocky Mountain area, have gradually widened this differential. Natural gas differentials are expected to remain approximately constant or to slightly widen in the first quarter of 2008 as compared to the $0.55 per Mcf differential we realized in the fourth quarter of 2007. We cannot accurately predict future crude oil and natural gas differentials. Increases in the differential between the NYMEX price for oil and natural gas and the wellhead price we receive could have a material adverse effect on our results of operations, financial position, and cash flows.

Capital resources. Our primary sources for cash are:

Cash flows from operating activities;

Cash flows from financing activities; and

Proceeds from sales of non-strategic assets.

Cash flows from operating activities. Cash provided by operating activities increased $22.4 million from $297.3 million in 2006 to $319.7 million in 2007. The increase was primarily due to an increase in our production margin, partially offset by increased settlements on our commodity derivative contracts as a result

ENCORE ACQUISITION COMPANY

of increases in oil prices and an increase in accounts receivable as a result of increased oil and natural gas production.

Cash provided by operating activities increased $5.1 million from $292.3 million in 2005 to $297.3 million in 2006. Total oil and natural gas revenues in 2006 increased $36.0 million, or eight percent, from 2005, which was offset by an increase of $33.9 million, or 13 percent, in total operating expenses (excluding marketing expenses) in 2006 from 2005.

Cash flows from investing activities. Cash used in investing activities increased $532.2 million from $397.4 million in 2006 to $929.6 million in 2007. The increase was primarily due to a $818.4 million increase in amounts paid for the acquisition of oil and natural gas properties, primarily our Big Horn Basin and Williston Basin acquisitions, partially offset by $286.4 million increase in proceeds received for the disposition of assets, primarily our Mid-Continent disposition. During 2007, we advanced $29.5 million (net of collections) to ExxonMobil for their portion of costs incurred drilling the commitment wells under the joint development agreement.

Cash used in investing activities decreased $176.1 million from $573.6 million in 2005 to $397.4 million in 2006. The decrease was primarily due to a $124.5 million decrease in amounts paid for the acquisition of oil and natural gas properties. Also, in 2005, we purchased all of the outstanding capital stock of Crusader Energy Corporation (Crusader), a privately held, independent oil and natural gas company, for a purchase price of approximately $109.6 million. During 2006, we advanced $22.4 million to ExxonMobil for their portion of costs incurred drilling the commitment wells under the joint development agreement.

Cash flows from financing activities. Our cash flows from financing activities consist primarily of proceeds from and payments on long-term debt and net proceeds from the sale of additional equity. We periodically draw on our revolving credit facility to fund acquisitions and other capital commitments. Historically, we have repaid large balances on our revolving credit facility with proceeds from the issuance of senior subordinated notes in order to extend the maturity date of the debt and fix the interest rate.

During 2007, we received net cash of $610.8 million from financing activities, including net borrowings on our revolving credit facilities of $444.8 million and net proceeds of $193.5 million from ENP s issuance of common units. Net borrowings on our revolving credit facilities resulted in an increase in outstanding borrowings under our revolving credit facilities from $68 million at December 31, 2006 to $526 million at December 31, 2007, primarily due to borrowings used to finance our Big Horn Basin and Williston Basin acquisitions, which were partially offset by repayments from the net proceeds received from the Mid-Continent disposition and ENP s issuance of common units.

During December 2007, we announced that the Board had approved a new share repurchase program authorizing the purchase of up to $50 million of our common stock. As of December 31, 2007, we had not repurchased any of our common shares under this program. As of February 25, 2008, we had repurchased 844,191 shares of our outstanding common stock for approximately $27.2 million, or an average price of $32.23 per share.

During 2006, we received net cash of $99.2 million from financing activities. On April 4, 2006, we received net proceeds of $127.1 million from a public offering of 4,000,000 shares of our common stock, which were used to repay outstanding balances under our revolving credit facility, invest in oil and natural gas activities, and pay general corporate expenses.

During 2005, we received net cash of $281.8 million from financing activities. In July 2005, we issued $300 million of 6.0% Notes and received net proceeds of approximately $294.5 million. In November 2005, we issued $150 million of 7.25% Notes and received net proceeds of approximately $148.5 million. We used a portion of the net proceeds to redeem all of our outstanding 83/8% Notes, pay the related early redemption premiums, and reduce outstanding borrowings under our revolving credit facility.

ENCORE ACQUISITION COMPANY

Liquidity. Our primary sources of liquidity are internally generated cash flows and the borrowing capacity under our revolving credit facility. We also have the ability to adjust our level of capital expenditures. We may use other sources of capital, including the issuance of additional debt or equity securities, to fund acquisitions, and to maintain our financial flexibility.

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 2007, realized oil prices increased by approximately 25 percent and realized natural gas prices remained virtually unchanged as compared to 2006. Realized oil and natural gas prices have historically fluctuated widely in response to changing market forces. For 2007, approximately 71 percent of our production was oil. As we previously discussed, our oil wellhead differentials during 2007 tightened as compared to 2006, favorably impacting the amount of oil revenues we received for our oil production. To the extent oil and natural gas prices decline or we experience significant widening of our wellhead differentials, our earnings, cash flows from operations, and availability under our revolving credit facility may be adversely impacted. Prolonged periods of low oil and natural gas prices or sustained wider than historical wellhead differentials could cause us to not be in compliance with financial covenants under our revolving credit facility and thereby affect our liquidity. We believe that our internally generated cash flows and unused availability under our revolving credit facility are sufficient to fund our planned capital expenditures for the foreseeable future.

Revolving credit facilities. Our principal source of short-term liquidity is our revolving credit facility.

Encore Acquisition Company Senior Secured Credit Agreement

On March 7, 2007, we entered into a five-year amended and restated credit agreement (the EAC Credit Agreement) with a bank syndicate comprised of Bank of America, N.A. and other lenders. The EAC Credit Agreement provides for revolving credit loans to be made to us from time to time and letters of credit to be issued from time to time for our account or any of our restricted subsidiaries. The aggregate amount of the commitments of the lenders under the EAC Credit Agreement is $1.25 billion. Availability under the EAC Credit Agreement is subject to a borrowing base, which is redetermined semi-annually and upon requested special redeterminations. As of December 31, 2007, the borrowing base was $870 million.

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

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

Ratio of Total Outstanding Borrowings to Borrowing Base	Applicable Margin for Eurodollar Loans	Applicable Margin for Base Rate Loans
Less than .50 to 1	1.000%	0.000%

Greater than or equal to .50 to 1 but less than .75 to 1	1.250%	0.000%
Greater than or equal to .75 to 1 but less than .90 to 1	1.500%	0.250%
Greater than or equal to .90 to 1	1.750%	0.500%

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

58

Table of Contents

ENCORE ACQUISITION COMPANY

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

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

- a prohibition against incurring debt, subject to permitted exceptions;
- a prohibition against paying dividends or making distributions, purchasing or redeeming capital stock, or prepaying indebtedness, subject to permitted exceptions;
- a restriction on creating liens on our and our restricted subsidiaries assets, subject to permitted exceptions;
- restrictions on merging and selling assets outside the ordinary course of business;
- restrictions on use of proceeds, investments, transactions with affiliates, or change of principal business;
- a provision limiting oil and natural gas hedging transactions (other than puts) to a volume not exceeding 75 percent of anticipated production from proved producing reserves;
- a requirement that we maintain a ratio of consolidated current assets to consolidated current liabilities of not less than 1.0 to 1.0; and
- a requirement that we maintain a ratio of consolidated EBITDA (as defined in the EAC Credit Agreement) to the sum of consolidated net interest expense plus letter of credit fees of not less than 2.5 to 1.0.

The EAC Credit Agreement contains customary events of default. If an event of default occurs and is continuing, lenders with a majority of the aggregate commitments may require Bank of America, N.A. to declare all amounts outstanding under the EAC Credit Agreement to be immediately due and payable.

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

Ratio of Total Outstanding Borrowings to Borrowing Base	**Commitment Fee Percentage**
Less than .50 to 1	0.250%
Greater than or equal to .50 to 1 but less than .75 to 1	0.300%
Greater than or equal to .75 to 1 but less than .90 to 1	0.375%
Greater than or equal to .90 to 1	0.375%

On December 31, 2007 and February 25, 2008, there were $478.5 million and $355 million of outstanding borrowings, respectively, and $371.5 million and $495 million of borrowing capacity, respectively, under the EAC Credit Agreement. As of December 31, 2007 and February 25, 2008, we had $20 million outstanding letters of credit, all of which related to our ExxonMobil joint development agreement.

Encore Energy Partners Operating LLC Credit Agreement

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

The aggregate amount of the commitments of the lenders under the OLLC Credit Agreement is $300 million. Availability under the OLLC Credit Agreement is subject to a borrowing base, which is redetermined semi-annually and upon requested special redeterminations. As of December 31, 2007, the borrowing base was $145 million. Upon completion of ENP s acquisition of certain oil and natural gas

ENCORE ACQUISITION COMPANY

producing properties and related assets in the Permian and Williston Basins from us as discussed above, the borrowing base was increased to $240 million.

The OLLC Credit Agreement matures on March 7, 2012. OLLC s obligations under the OLLC Credit Agreement are secured by a first-priority security interest in OLLC s and its restricted subsidiaries proved oil and natural gas reserves and in the equity interests of OLLC and its restricted subsidiaries. In addition, OLLC s obligations under the OLLC Credit Agreement are guaranteed by ENP and OLLC s restricted subsidiaries. We consolidate the debt of ENP with that of our own; however, obligations under the OLLC Credit Agreement are non-recourse to us and our restricted subsidiaries.

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

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

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

- a prohibition against incurring debt, subject to permitted exceptions;
- a prohibition against purchasing or redeeming capital stock, or prepaying indebtedness, subject to permitted exceptions;
- a restriction on creating liens on the assets of ENP, OLLC and its restricted subsidiaries, subject to permitted exceptions;
- restrictions on merging and selling assets outside the ordinary course of business;
- restrictions on use of proceeds, investments, transactions with affiliates, or change of principal business;
- a provision limiting oil and natural gas hedging transactions (other than puts) to a volume not exceeding 75 percent of anticipated production from proved producing reserves;
- a requirement that OLLC maintain a ratio of consolidated current assets to consolidated current liabilities of not less than 1.0 to 1.0;
- a requirement that OLLC maintain a ratio of consolidated EBITDA (as defined in the OLLC Credit Agreement) to the sum of consolidated net interest expense plus letter of credit fees of not less than 1.5 to 1.0;
- a requirement that OLLC maintain a ratio of consolidated EBITDA (as defined in the OLLC Credit Agreement) to consolidated senior interest expense of not less than 2.5 to 1.0; and
- a requirement that OLLC maintain a ratio of consolidated funded debt (excluding certain related party debt) to consolidated adjusted EBITDA (as defined in the OLLC Credit Agreement) of not more than 3.5 to 1.0.

The OLLC Credit Agreement contains customary events of default. If an event of default occurs and is continuing, lenders with a majority of the aggregate commitments may require Bank of America, N.A. to declare all amounts outstanding under the OLLC Credit Agreement to be immediately due and payable. At December 31, 2007, OLLC was in compliance with all covenants of the OLLC Credit Agreement, as amended.

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

On December 31, 2007 and February 25, 2008, there were $47.5 million and $169.5 million of outstanding borrowings, respectively, and $97.4 million and $70.4 million of borrowing capacity, respectively,

ENCORE ACQUISITION COMPANY

under the OLLC Credit Agreement. As of December 31, 2007 and February 25, 2008, ENP had $0.1 million outstanding letters in credit.

Please read Note 8 of Notes to Consolidated Financial Statements included in Item 8. Financial Statements and Supplementary Data for additional information regarding our long-term debt.

Subsequent to December 31, 2007, as a result of the increase in debt levels resulting from the Elk Basin acquisition, ENP entered into interest rate swaps whereby it swapped $100 million of floating rate debt to a fixed rate with a LIBOR rate of 3.06 percent and an expected margin of 1.25 percent on 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 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; and
- consolidate, merge, or transfer assets.

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.

Debt covenants. At December 31, 2007, we were in compliance with all of our debt covenants.

Current capitalization. At December 31, 2007, we had total assets of $2.8 billion and total capitalization of $2.1 billion, of which 46 percent was represented by stockholders equity and 54 percent by long-term debt. At December 31, 2006, we had total assets of $2.0 billion and total capitalization of $1.5 billion, of which 55 percent was represented by stockholders equity and 45 percent by long-term debt. The percentages of our capitalization represented by stockholders equity and long-term debt could vary in the future if debt is used to finance future capital projects or potential acquisitions.

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 have been and will continue to be affected by changes in oil and natural gas prices. Historically, significant fluctuations have occurred in oil and natural gas prices. The following table indicates the average oil and natural gas prices for 2007, 2006, and 2005. Average realized equivalent prices for 2007,

ENCORE ACQUISITION COMPANY

2006, and 2005 were decreased by $3.96, $5.37, and $5.71 per BOE, respectively, as a result of our commodity derivative contracts.

	Year Ended December 31,		
	2007	2006	2005
Average Realized Prices:			
Oil ($/Bbl)	$ 58.96	$ 47.30	$ 44.82
Natural gas ($/Mcf)	6.26	6.24	7.09
Combined ($/BOE)	52.66	43.87	44.05
Average Wellhead Prices:			
Oil ($/Bbl)	$ 63.50	$ 54.42	$ 51.06
Natural gas ($/Mcf)	6.69	6.59	7.87
Combined ($/BOE)	56.62	49.24	49.76

The increase in oil and natural gas prices may be accompanied by or result in: (i) increased development costs, as the demand for drilling operations continues to increase; (ii) 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; (iii) increased LOE due to increased demand for services related to the operation of our wells; and (iv) increased electricity costs. We believe our risk management program and available borrowing capacity under our revolving credit facility provide means for us to manage commodity price risks through our commodity derivative program.

Critical Accounting Policies and Estimates

The preparation of financial statements in accordance with U.S. generally accepted accounting principles requires management to make estimates and assumptions that affect reported amounts 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.

Oil and Natural Gas Properties

Successful efforts method. We use the successful efforts method of accounting for oil and natural gas properties under 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 our Consolidated Statements of Operations and shown as a non-cash adjustment to net income in the Operating activities section of our Consolidated Statements of Cash Flows in the period in which the determination is made. If an exploratory well finds reserves but they cannot be classified as proved, we will 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 towards assessing the reserves and the operating viability of the project. If subsequently it is determined that neither of these conditions continue to exist, all previously capitalized costs associated with the exploratory well are expensed and shown as a non-cash adjustment to net income in the Operating activities section of our Consolidated Statements of Cash Flows in the period in which the determination is made. Re-drilling or directional drilling in a previously abandoned well would be classified as development or exploratory based on whether it is in a proved or unproved reservoir for determination of

ENCORE ACQUISITION COMPANY

capital or expense. Expenditures for repairs and maintenance to sustain or increase production from the existing producing reservoir are charged to expense as incurred. Expenditures to recomplete a current well in a different unproved reservoir are capitalized pending determination that economic reserves have been added. If the recompletion is not successful, the expenditures would be charged to expense.

DD&A expense is directly affected by our reserve estimates. Any change in reserves directly impacts the amount of DD&A expense that we recognize in a given period. 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. Changes in future commodity prices would likely result in increases or decreases in estimated recoverable reserves. DD&A expense associated with lease and well equipment and intangible drilling costs is based upon only 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 & Lents estimates our reserves annually at December 31.

Significant tangible equipment added or replaced that extends the useful or productive life of the property is capitalized. Expenditures 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 total proved developed reserves or proved reserves, as applicable. Natural gas volumes are converted to BOE at the rate of six Mcf to one Bbl of oil. 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.

The costs of retired, sold, or abandoned properties that constitute part of an amortization base are charged or credited, net of proceeds received, to the accumulated DD&A reserve. Gains or losses from the disposal of other properties are recognized in the current period.

In accordance with SFAS No. 144, *Accounting for the Impairment or Disposal of Long-Lived Assets*, an impairment of capitalized costs of long-lived assets to be held and used, including proved oil and natural gas properties, must be assessed 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 reserve and production information and pricing assumptions that management believes are reasonable. Any impairment charge incurred is expensed and reduces our recorded basis in the asset. Management currently 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 used in bidding on acquisitions and/or assessing capital projects. These price assumptions are critical to the impairment analysis as lower prices could trigger impairment while higher prices would have the opposite effect.

Unproved properties, the majority of the costs of which relates 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 an impairment, a loss is recognized by providing a valuation allowance at the level consistent with 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 feel 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

ENCORE ACQUISITION COMPANY

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. Unproved properties had a net book value of $63.4 million and $47.5 million as of December 31, 2007 and 2006, respectively. We recorded charges for unproved acreage impairment in the amounts of $10.8 million, $10.9 million, and $2.0 million in 2007, 2006, and 2005, respectively.

Oil and natural gas reserves. Our estimates of proved reserves are based on the quantities of oil and natural gas that engineering and geological analyses demonstrate, with reasonable certainty, to be recoverable from established reservoirs in the future under current operating and economic parameters. 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;
- the interpretation of that data;
- the accuracy of various mandated economic assumptions; and
- the 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 depletion rate.

Asset retirement obligations. In accordance with SFAS No. 143, *Accounting for Asset Retirement* Obligations , we estimate our eventual obligations associated with the retirement of tangible long-lived assets that result from the acquisition, construction, and development of our oil and natural gas wells and related facilities. 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 at its discounted fair value. The liability is then accreted up by recording expense each period until it is settled or the well 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 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

Goodwill represents the excess of the purchase price over the estimated fair value of the net assets acquired in business combinations. We assess goodwill for impairment on an annual basis or whenever indicators of impairment exist. We performed our annual impairment test at December 31, 2007, and determined that no indicators of impairment existed. If indicators of impairment are determined to exist, we would recognize an impairment charge for any amount by which the carrying value of goodwill exceeds the

ENCORE ACQUISITION COMPANY

implied fair value of the goodwill. The goodwill test is performed at the reporting unit level. We have determined that we have two operating segments: EAC Standalone and ENP. All goodwill has been allocated to the EAC Standalone segment.

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 NPI ranging from one percent to 50 percent. The holders of these NPIs 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 NPIs are deducted from our reserves and production data, and our revenues are reported net of NPI payments. The reserves and production attributed to the NPIs are calculated by dividing estimated future NPI payments (in the case of reserves) or prior period actual NPI payments (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 NPIs and will have an inverse effect on our reported reserves and production. Based largely on a continued increase in commodity prices and production volumes, we expect to make higher NPI payments in 2008 and possibly beyond than we have in previous years, which directly impacts our oil and natural gas revenues, production, reserves, and net income.

Revenue Recognition

Revenues are recognized as oil and natural gas is produced and sold, net of royalties and NPI payments. Natural gas revenues are also reduced by any processing and other fees paid 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 our actual sales of natural gas rather than our equity share of natural gas production. Royalties, NPIs, and severance taxes are paid 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. If our overproduced imbalance position (i.e., we have cumulatively been over-allocated production) is greater than our share of remaining reserves, we record a liability for the excess at period-end prices. We also do not recognize revenue for the production in tanks, oil marketed on behalf of joint interest owners in our properties, or oil that resides in pipelines prior to delivery to the purchaser. Our net oil inventories in pipelines were 124,410 Bbls and 146,284 Bbls at December 31, 2007 and 2006, respectively. Natural gas imbalances at December 31, 2007 and 2006, were 128,856 MMBtu and 188,757 MMBtu under-delivered to us, respectively.

Income Taxes

Effective tax rate. 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 tax paying 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 current period earnings.

Table of Contents

ENCORE ACQUISITION COMPANY

Commodity Derivative Contracts and Related Activities

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 has no effect on our cash flows, our results of operations are affected by mark-to-market gains and losses, which fluctuate with the changes in oil and natural gas prices. The net deferred losses in Accumulated Other Comprehensive Loss (AOCL) at the time of dedesignation are being amortized to oil and natural gas revenues over the original term of the contracts which extend through June 30, 2008. The amortization of these amounts is included in oil and natural gas revenues with the revenues from the hedged production. All mark-to-market gains and losses from July 2006 forward are recognized in earnings rather than deferring such amounts in AOCL.

New Accounting Pronouncements

FASB Interpretation No. 48, Accounting for Uncertainty in Income Taxes an Interpretation of FASB Statement No. 109 (FIN 48)

On January 1, 2007, we adopted the provisions of FIN 48, which clarifies the accounting for uncertainty in income taxes recognized in an entity s financial statements in accordance with SFAS No. 109, *Accounting for Income Taxes* . FIN 48 prescribes a recognition threshold and measurement attribute for the financial statement recognition and measurement of a tax position taken or expected to be taken in a tax return. We have performed an evaluation of tax positions and determined that the adoption of FIN 48 did not have a material impact on our financial condition, results of operations, or cash flows.

SFAS No. 157, Fair Value Measurement (SFAS 157)

In September 2006, the FASB issued SFAS 157. SFAS 157 standardizes the definition of fair value, establishes a framework for measuring fair value in generally accepted accounting principles, and expands disclosures related to the use of fair value measures in financial statements. SFAS 157 applies whenever other standards require (or permit) assets or liabilities to be measured at fair value but does not require any new fair value measurements. SFAS 157 is prospectively effective for financial assets and liabilities for financial statements issued for fiscal years beginning after November 15, 2007, and interim periods within those fiscal years. On February 12, 2008, the FASB issued FASB Staff Position (FSP) 157-2 (FSP 157-2) which delays the effective date of SFAS 157 for one year, for all 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). We have elected a partial deferral of SFAS 157 for all instruments within the scope of FSP 157-2 including but not limited to our asset retirement obligations and indefinite lived assets. We will continue to evaluate the impact of SFAS 157 on these instruments during the deferral period. SFAS 157, as it relates to financial assets and liabilities, is effective beginning in the first quarter of 2008. We do not currently expect the adoption of SFAS 157 to have a material impact on our results of operations or financial condition, however, the fair value of our derivative instruments has always been dependent on multiple variables that can be volatile and unpredictable, therefore, any impact of adopting SFAS 157 will not be known for certain until the end of each reporting period.

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

In February 2007, the FASB issued SFAS 159. SFAS 159 permits entities to measure many financial instruments and certain other assets and liabilities at fair value on an instrument-by-instrument basis. SFAS 159 allows entities to measure eligible items at fair value at specified election dates, with resulting changes in fair value reported in earnings. SFAS 159 is effective for fiscal years beginning after November 15, 2007. We do not expect the adoption of SFAS 159 to have a material impact on our results of operations or financial condition.

Table of Contents

ENCORE ACQUISITION COMPANY

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

In April 2007, the FASB issued FSP FIN 39-1. FSP FIN 39-1 amends FIN No. 39, *Offsetting of Amounts Related to Certain Contracts* (FIN 39), to permit a reporting entity that is party to a master netting arrangement to offset the fair value amounts recognized for the right to reclaim cash collateral (a receivable) or the obligation to return cash collateral (a payable) against fair value amounts recognized for derivative instruments that have been offset under the same master netting arrangement in accordance with FIN 39. FSP FIN 39-1 is effective for fiscal years beginning after November 15, 2007. We do not expect the adoption of FSP FIN 39-1 to have a material impact on our results of operations or financial condition.

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

In December 2007, the FASB issued SFAS 141R. SFAS 141R is a revision of SFAS No. 141, *Business Combinations* (SFAS 141). SFAS 141R amends SFAS 141 by requiring an acquirer to recognize: (i) the assets acquired, liabilities assumed, and any noncontrolling interest in the acquiree at fair value as of the acquisition date, (ii) a gain attributable to any negative goodwill in a bargain purchase, and (iii) an expense related to acquisition costs. SFAS 141R is effective as of the beginning of an entity s first fiscal year that begins on or after December 15, 2008. We do not expect the adoption of SFAS 141R to have a material impact on our current results of operations or financial condition. However, future results of operations or financial condition may be materially affected if we have a significant acquisition.

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

In December 2007, the FASB issued SFAS 160. SFAS 160 amends Accounting Research Bulletin No. 51, *Consolidated Financial Statements* (ARB 51) to establish accounting and reporting standards for the noncontrolling interest in a subsidiary and for the deconsolidation of a subsidiary. SFAS 160 is effective as of the beginning of an entity s first fiscal year that begins on or after December 15, 2008. We expect the adoption of SFAS 141R to have a material impact on how we account for and disclose the noncontrolling interest in ENP.

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

- expected capital expenditures and the focus of our capital program;
- areas of future growth;
- our development program;
- future horizontal development, secondary development, and tertiary recovery potential;

the implementation of our HPAI programs, the ability to expand the program to other parts of the CCA and the effects thereof;

the completion of current HPAI projects and the effects thereof;

anticipated prices for oil and natural gas and expectations regarding differentials between wellhead prices and benchmark prices (including, without limitation, the effects of increased Canadian oil production and refinery turnarounds);

ENCORE ACQUISITION COMPANY

- 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;
- expectations regarding working capital, cash flow, and liquidity;
- projected borrowings under our revolving credit facility; 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.

ITEM 7A. *QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK*

Derivative policy. The purpose of our derivative program is to mitigate the negative effects of declining commodity prices on our business. We plan to continue in the normal course of business to manage our exposure to fluctuating commodity prices through the use of commodity derivative contracts. In very limited circumstances, we may enter into derivative financial instruments to achieve other goals. From time to time, we use fixed to floating interest rate swaps to offset interest expense on our fixed rate debt. We weigh the increased risk of the instrument versus the potential cash flow savings before entering into any derivative instrument designed to achieve any goal other than risk reduction.

Counterparties. At December 31, 2007, we had committed greater than 10 percent of either our outstanding oil or natural gas commodity derivative contracts to the following counterparties:

Counterparty	Percentage of Oil Derivative Contracts Committed	Percentage of Natural Gas Derivative Contracts Committed
Bank of America, N.A.	18%	
BNP Paribas	25%	40%

Calyon	10%	28%
Deutsche Bank	20%	
Wachovia	10%	32%

We believe our credit-worthiness as well as that of our current counterparties is sound and we do not anticipate any non-performance of contractual obligations. As long as each counterparty maintains an investment grade credit rating, no collateral is required.

In order to mitigate the credit risk of financial instruments, we enter into master netting agreements with significant counterparties. The master netting agreement is a standardized, bilateral contract between a given counterparty and us. Instead of treating separately each financial transaction between our counterparty and us, the master netting agreement enables our counterparty and us to aggregate all financial trades and treat them as a single agreement. This arrangement benefits us in three ways: (i) the netting of the value of all trades reduces the requirements of daily collateral posting by us, (ii) default by a counterparty under one financial trade can trigger rights for us to terminate all financial trades with such counterparty, and (iii) netting of settlement amounts reduces our credit exposure to a given counterparty in the event of close-out.

Table of Contents

ENCORE ACQUISITION COMPANY

Commodity price sensitivity. The tables in this section provide information about our commodity derivative contracts to which we were a party as of December 31, 2007 that are sensitive to changes in oil and natural gas commodity prices.

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. Additionally, we may occasionally short sell put contracts with a strike price well below the floor price of a floor or collar in order to offset some of the cost of the contract. Combined, the short floor and long floor are called a floor spread. As of December 31, 2007, the unrealized loss on commodity derivative contracts which were previously designated as hedges was approximately $1.8 million and is reflected in AOCL in our Consolidated Balance Sheet. As of December 31, 2007, the fair market value of our oil and natural gas commodity derivative contracts was a net asset of $2.7 million and $7.1 million, respectively. Based on our open commodity derivative positions at December 31, 2007, a $1.00 increase in the respective NYMEX prices for oil and natural gas would decrease our net derivative fair value asset by approximately $9.1 million, while a $1.00 decrease in the respective NYMEX prices for oil and natural gas would increase our net derivative fair value asset by approximately $11.9 million. These amounts exclude deferred premiums of $51.9 million at December 31, 2007 that are not subject to changes in commodity prices.

Oil Derivative Contracts

Period	Daily Floor Volume (Bbl)	Average Floor Price (per Bbl)	Daily Short Floor Volume (Bbl)	Average Short Floor Price (per Bbl)	Daily Cap Volume (Bbl)	Average Cap Price (per Bbl)	Daily Swap Volume (Bbl)	Average Swap Price (per Bbl)	Asset (Liability) Fair Market Value (in thousands)
Jan. 2008	4,000	$ 80.00		$	2,000	$ 100.75		$	$ (1,313)
	6,000	71.67			2,000	96.65			
	11,500	61.96	(2,000)	65.00					
	3,000	56.67	(4,000)	50.00			1,000	58.59	
Feb. June 2008	4,880	80.00			2,440	101.99			(6,714)
	6,000	71.67			2,000	96.65			
	11,500	61.96	(2,000)	65.00					
	3,000	56.67	(4,000)	50.00			1,000	58.59	
Second Half 2008	4,880	80.00			2,440	101.99	3,000	90.26	(341)
	6,000	71.67			2,000	96.65			
	7,500	63.00	(2,000)	65.00					
	3,000	56.67	(4,000)	50.00					
2009	880	80.00			440	97.75			9,222
	12,250	72.96	(1,250)	65.00					

	3,750	64.47	(5,000)	50.00			1,000	68.70	
2010	880	80.00			440	93.80			52
	2,000	75.00			1,000	77.23			
	2,000	65.00	(2,000)	65.00					
2011	1,000	80.00			1,000	94.65			1,811
	1,000	70.00							
									$ 2,717

Table of Contents

ENCORE ACQUISITION COMPANY

Natural Gas Derivative Contracts

Period	Daily Floor Volume (Mcf)	Average Floor Price (per Mcf)	Daily Short Floor Volume (Mcf)	Average Short Floor Price (per Mcf)	Daily Cap Volume (Mcf)	Average Cap Price (per Mcf)	Daily Swap Volume (Mcf)	Average Swap Price (per Mcf)	Asset Fair Market Value (In thousands)
Jan. 2008	2,000	$ 8.20		$	2,000	$ 9.85		$	$ 159
	2,000	7.20							
	20,000	6.35							
Feb. - Dec. 2008	3,800	8.20			3,800	9.83			4,306
	3,800	7.20							
	20,000	6.35							
2009	3,800	8.20			3,800	9.83			1,376
	3,800	7.20							
2010	3,800	8.20			3,800	9.58			1,240
	3,800	7.20							
									$ 7,081

Interest rate sensitivity. At December 31, 2007, we had total long-term debt of $1.1 billion, which is recorded net of discount of $5.8 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 percent, and $150 million bears interest at a fixed rate of 7.25 percent. The remaining outstanding long-term debt balance of $526 million is under our revolving credit facilities and is subject to floating market rates of interest that are linked to LIBOR.

At this level of floating rate debt, if LIBOR increased one percent, we would incur an additional $5.3 million of interest expense per year on our revolving credit facilities, and if LIBOR decreased one percent, we would incur $5.3 million less. Additionally, if LIBOR increased one percent, we estimate the fair value of our fixed rate debt at December 31, 2007 would decrease from $546.9 million to $540.9 million, and if LIBOR decreased one percent, we estimate the fair value would increase to $552.9 million.

Subsequent to December 31, 2007, as a result of the increase in debt levels resulting from the aforementioned acquisition of assets in the Permian and Williston Basins, ENP entered into interest rate swaps whereby it swapped $100 million of floating rate debt to a fixed rate with a LIBOR rate of 3.06 percent and an expected margin of 1.25 percent on the OLLC Credit Agreement.

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, 2007 and 2006, and the related consolidated statements of operations, stockholders equity and comprehensive income, and cash flows for each of the three years in the period ended December 31, 2007. 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 consolidated financial statements referred to above present fairly, in all material respects, the consolidated financial position of Encore Acquisition Company at December 31, 2007 and 2006, and the consolidated results of its operations and its cash flows for each of the three years in the period ended December 31, 2007, in conformity with U.S. generally accepted accounting principles.

As explained in Note 9 to the consolidated financial statements, effective January 1, 2007, the Company adopted FASB Interpretation No. 48, *Accounting for Uncertainty in Income Taxes an Interpretation of FASB No. 109* . As explained in Note 2 to the consolidated financial statements, effective January 1, 2006, the Company adopted Statement of Financial Accounting Standards No. 123R, *Share-Based Payment* .

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the Company s internal control over financial reporting as of December 31, 2007, 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 27, 2008 expressed an unqualified opinion thereon.

/s/ Ernst & Young LLP

Fort Worth, Texas
February 27, 2008

Table of Contents

ENCORE ACQUISITION COMPANY

CONSOLIDATED BALANCE SHEETS

	December 31, 2007	December 31, 2006
	(In thousands, except share and per share amounts)	
ASSETS		
Current assets:		
Cash and cash equivalents	$ 1,704	$ 763
Accounts receivable, net of allowance for doubtful accounts of $6,045 and $2,329, respectively	134,880	81,470
Inventory	16,257	18,170
Derivatives	9,722	17,349
Deferred taxes	20,420	24,978
Other	5,527	2,988
Total current assets	188,510	145,718
Properties and equipment, at cost successful efforts method:		
Proved properties, including wells and related equipment	2,845,776	2,033,914
Unproved properties	63,352	47,548
Accumulated depletion, depreciation, and amortization	(489,004)	(364,780)
	2,420,124	1,716,682
Other property and equipment	21,750	18,231
Accumulated depreciation	(10,733)	(7,791)
	11,017	10,440
Goodwill	60,606	60,606
Derivatives	34,579	40,715
Long-term receivables	40,945	19,642
Other	28,780	13,097
Total assets	$ 2,784,561	$ 2,006,900
LIABILITIES AND STOCKHOLDERS EQUITY		
Current liabilities:		
Accounts payable	$ 21,548	$ 18,204
Accrued liabilities:		
Lease operations expense	15,057	8,582
Development capital	48,359	44,492
Interest	12,795	11,273

Production, ad valorem, and severance taxes	24,694	10,915
Oil purchases	8,721	11,191
Derivatives	39,337	60,448
Oil and natural gas revenues payable	13,076	8,612
Other	21,143	12,746
Total current liabilities	204,730	186,463
Derivatives	47,091	38,688
Future abandonment cost	27,371	19,205
Deferred taxes	312,914	282,825
Long-term debt	1,120,236	661,696
Other	1,530	1,158
Total liabilities	1,713,872	1,190,035
Commitments and contingencies (see Note 4)		
Minority interest in consolidated partnership	122,534	
Stockholders equity:		
Preferred stock, $.01 par value, 5,000,000 shares authorized, none issued and outstanding		
Common stock, $.01 par value, 144,000,000 shares authorized, 53,303,464 and 53,028,866 issued and outstanding, respectively	534	531
Additional paid-in capital	538,620	457,201
Treasury stock, at cost, of 17,690 and 17,809 shares, respectively	(590)	(457)
Retained earnings	411,377	394,917
Accumulated other comprehensive loss	(1,786)	(35,327)
Total stockholders equity	948,155	816,865
Total liabilities and stockholders equity	$ 2,784,561	$ 2,006,900

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

Table of Contents

ENCORE ACQUISITION COMPANY

CONSOLIDATED STATEMENTS OF OPERATIONS

	Year Ended December 31,		
	2007	2006	2005
	(In thousands, except per share amounts)		
Revenues:			
Oil	$ 562,817	$ 346,974	$ 307,959
Natural gas	150,107	146,325	149,365
Marketing	42,021	147,563	
Total revenues	754,945	640,862	457,324
Expenses:			
Production:			
Lease operations	143,426	98,194	69,744
Production, ad valorem, and severance taxes	74,585	49,780	45,601
Depletion, depreciation, and amortization	183,980	113,463	85,627
Exploration	27,726	30,519	14,443
General and administrative	39,124	23,194	17,268
Marketing	40,549	148,571	
Derivative fair value loss (gain)	112,483	(24,388)	5,290
Loss on early redemption of debt			19,477
Provision for doubtful accounts	5,816	1,970	231
Other operating	17,066	8,053	9,254
Total expenses	644,755	449,356	266,935
Operating income	110,190	191,506	190,389
Other income (expenses):			
Interest	(88,704)	(45,131)	(34,055)
Other	2,667	1,429	1,039
Total other income (expenses)	(86,037)	(43,702)	(33,016)
Income before income taxes and minority interest	24,153	147,804	157,373
Income tax provision	(14,476)	(55,406)	(53,948)
Minority interest in loss of consolidated partnership	7,478		
Net income	$ 17,155	$ 92,398	$ 103,425
Net income per common share:			

Basic	$ 0.32	$ 1.78	$ 2.12
Diluted	$ 0.32	$ 1.75	$ 2.09
Weighted average common shares outstanding:			
Basic	53,170	51,865	48,682
Diluted	54,144	52,736	49,522

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

Table of Contents

ENCORE ACQUISITION COMPANY

CONSOLIDATED STATEMENTS OF STOCKHOLDERS EQUITY AND COMPREHENSIVE INCOME

	Issued Shares of Common Stock	Common Stock	Additional Paid-in Capital	Shares of Treasury Stock	Treasury Stock	Retained Earnings	Accumulated Other Comprehensive Loss	Total Stockholders Equity
				(In thousands)				
Balance at December 31, 2004	48,654	$ 487	$ 309,973		$	$ 199,512	$ (36,397)	$ 473,575
Exercise of stock options and vesting of restricted stock	138	1	2,817					2,818
Purchase of treasury stock				(18)	(570)			(570)
Cancellation of treasury stock	(7)		(133)	7	195	(62)		
Non-cash stock-based compensation			3,962					3,962
Components of comprehensive income:								
Net income						103,425		103,425
Change in deferred hedge gain/loss, net of tax of $21,701							(36,429)	(36,429)
Total comprehensive income								66,996
Balance at December 31, 2005	48,785	488	316,619	(11)	(375)	302,875	(72,826)	546,781
Exercise of stock options and vesting of restricted stock	280	3	3,641					3,644
				(25)	(633)			(633)

Purchase of treasury stock								
Cancellation of treasury stock	(18)		(195)	18	551	(356)		
Issuance of common stock	4,000	40	127,061					127,101
Non-cash stock-based compensation			10,075					10,075
Components of comprehensive income:								
Net income						92,398		92,398
Change in deferred hedge gain/loss, net of tax of $22,365							37,499	37,499
Total comprehensive income								129,897
Balance at December 31, 2006	53,047	531	457,201	(18)	(457)	394,917	(35,327)	816,865
Exercise of stock options and vesting of restricted stock	313	3	1,587					1,590
Purchase of treasury stock				(39)	(1,136)			(1,136)
Cancellation of treasury stock	(39)		(338)	39	1,003	(665)		
Non-cash equity-based compensation			14,632					14,632
EAC s share of ENP s offering costs			(12,088)					(12,088)
ENP distributions						(30)		(30)
Adjustment to reflect gain on sale of ENP common units			77,626					77,626
Components of comprehensive income:								
Net income						17,155		17,155
Amortization of deferred hedge losses, net of tax							33,541	33,541

of $20,047														
Total comprehensive income														50,696
Balance at December 31, 2007	53,321	$	534	$	538,620	(18)	$	(590)	$	411,377	$	(1,786)	$	948,155

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

ENCORE ACQUISITION COMPANY

CONSOLIDATED STATEMENTS OF CASH FLOWS

	Year Ended December 31, 2007	2006	2005
	(In thousands)		
Cash flows from operating activities:			
Net income	$ 17,155	$ 92,398	$ 103,425
Adjustments to reconcile net income to net cash provided by operating activities:			
Depletion, depreciation, and amortization	183,980	113,463	85,627
Non-cash exploration expense	25,487	28,128	10,706
Deferred taxes	12,588	51,220	56,032
Non-cash equity-based compensation expense	15,997	8,980	3,962
Non-cash derivative loss (gain)	130,910	(10,434)	12,637
Loss (gain) on disposition of assets	7,409	(297)	352
Loss on early redemption of debt			19,477
Minority interest in loss of consolidated partnership	(7,478)		
Provision for doubtful accounts	5,816	1,970	231
Other	10,182	7,577	1,912
Changes in operating assets and liabilities, net of effects from acquisitions:			
Accounts receivable	(48,647)	(2,275)	(30,423)
Current derivatives	(17,430)		(2,029)
Other current assets	3,108	(4,945)	(4,067)
Long-term derivatives	(35,750)		(3,517)
Other assets	(1,214)	(365)	(1,281)
Accounts payable	4,461	1,833	(444)
Other current liabilities	14,788	10,080	39,839
Other noncurrent liabilities	(1,655)		(170)
Net cash provided by operating activities	319,707	297,333	292,269
Cash flows from investing activities:			
Proceeds from disposition of assets	287,928	1,522	753
Purchases of other property and equipment	(3,519)	(4,290)	(6,767)
Acquisition of oil and natural gas properties	(848,545)	(30,119)	(154,615)
Acquisition of Crusader Energy Corporation, net of cash acquired			(91,095)
Development of oil and natural gas properties	(335,897)	(340,582)	(321,836)
Net advances to working interest partners	(29,523)	(22,425)	
Other		(1,536)	
Net cash used in investing activities	(929,556)	(397,430)	(573,560)
Cash flows from financing activities:			
Proceeds from issuance of common stock, net of issuance costs		127,101	

Proceeds from issuance of ENP common units, net of issuance costs	193,461		
Exercise of stock options and vesting of restricted stock, net of treasury stock purchases	454	3,011	898
Proceeds from long-term debt, net of issuance costs	1,479,259	281,853	997,446
Payments on long-term debt	(1,034,428)	(294,000)	(719,852)
Payment of commodity derivative contract premiums	(26,195)	(7,848)	
ENP distributions	(568)		
Change in cash overdrafts	(1,193)	(10,911)	3,350
Net cash provided by financing activities	610,790	99,206	281,842
Increase (decrease) in cash and cash equivalents	941	(891)	551
Cash and cash equivalents, beginning of period	763	1,654	1,103
Cash and cash equivalents, end of period	$ 1,704	$ 763	$ 1,654

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

Table of Contents

ENCORE ACQUISITION COMPANY

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

Note 1. About EAC and Basis of Presentation

Encore Acquisition Company (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 of Montana and North Dakota;
- the Permian Basin of West Texas and southeastern New Mexico;
- the Rockies, which includes non-CCA assets in the Williston, Big Horn, and Powder River Basins of Wyoming, Montana, and North Dakota, and the Paradox Basin of southeastern Utah; and
- the Mid-Continent area, which includes the Arkoma and Anadarko Basins of Oklahoma, the North Louisiana Salt Basin, and the East Texas Basin.

In February 2007, EAC formed Encore Energy Partners LP (ENP), a publicly traded Delaware limited partnership, 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) of 9,000,000 common units, representing a 37.4 percent limited partner interest, at a price to the public of $21.00 per unit. In October 2007, the underwriters exercised their over-allotment option to purchase an additional 1,148,400 common units of ENP, representing an additional 2.9 percent limited partner interest. As of December 31, 2007, EAC owned approximately 58 percent of ENP s common units, as well as all of the interests of Encore Energy Partners GP LLC (GP LLC), a Delaware limited liability company and ENP s general partner, which is an indirect wholly owned non-guarantor subsidiary of EAC. Considering the presumption of control of GP LLC in accordance with Emerging Issues Task Force (EITF) Issue No. 04-5, *Determining Whether a General Partner, or the General Partners as a Group, Controls a Limited Partnership or Similar Entity When the Limited Partners Have Certain Rights* , the financial position, results of operations, and cash flows of ENP are consolidated within EAC s operations. EAC elected to account for gains on ENP s issuance of common units as capital transactions as permitted by Staff Accounting Bulletin Topic 5H, *Accounting for Sales of Stock by a Subsidiary* . See Note 16. ENP for additional discussion.

Variable Interest Entity

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

The Williston Basin acquisition was structured to qualify as the first step of a reverse like-kind exchange under Section 1031 of the Internal Revenue Code of 1986, as amended, and I.R.S. Revenue Procedure 2000-37. The Williston Basin assets were acquired by Encore Exchange as an exchange accommodation titleholder . Encore

Exchange held the assets pursuant to a qualified exchange accommodation agreement until the second step of the like-kind exchange was completed. During the period the assets were held by Encore Exchange, Encore Operating operated the Williston Basin assets pursuant to a management agreement with Encore Exchange. The second step of the like-kind exchange was completed in July 2007 upon the completion

Table of Contents

ENCORE ACQUISITION COMPANY

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

of the disposition of certain of EAC s Mid-Continent properties and the Williston Basin assets were transferred to EAC. See Note 3. Acquisitions and Dispositions for additional discussion.

In connection with the like-kind exchange described above, EAC (through Encore Operating) loaned an amount equal to the purchase price to Encore Exchange. Based on the provisions of Financial Accounting Standards Board (FASB) Interpretation (FIN) No. 46(R), *Consolidation of Variable Interest Entities* , EAC determined that Encore Exchange was a variable interest entity for which EAC was the primary beneficiary. During the third quarter of 2007, the like-kind exchange was completed, and Encore Exchange was dissolved. As of December 31, 2007, EAC had no interest in variable interest entities.

Minority Interest

As presented in the accompanying Consolidated Balance Sheets, Minority interest in consolidated partnership as of December 31, 2007 of $122.5 million represents third-party ownership interests in ENP. For financial reporting purposes, the assets and liabilities of ENP are consolidated with those of EAC, with any third-party ownership interests in such amounts being presented as minority interest.

As presented in the accompanying Consolidated Statements of Operations, Minority interest in loss of consolidated partnership for 2007 of $7.5 million represents the net loss of ENP attributable to third-party owners.

Reclassifications

Certain amounts in prior periods have been reclassified to conform to the current period presentation. In particular, Provision for doubtful accounts has been presented separately on the accompanying Consolidated Statements of Operations and the Consolidated Statements of Cash Flows and certain amounts on the accompanying Consolidated Statements of Cash Flows have been either combined or classified in more detail.

Note 2. Summary of Significant Accounting Policies

Principles of Consolidation

EAC s consolidated financial statements include the accounts of wholly owned and majority-owned subsidiaries. All material intercompany balances and transactions have been eliminated in consolidation. See Note 1. About EAC and Basis of Presentation for a description of the consolidation policies for variable interest entities and minority interest.

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, 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.

Accounts Receivable

EAC s 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 the current portion of balances due from ExxonMobil Corporation (ExxonMobil) in connection with our joint development agreement. See Note 4. Commitments and Contingencies for additional discussion of this agreement. EAC routinely reviews outstanding accounts receivable balances and assesses the financial strength of its customers. A reserve is recorded for amounts it expects will not be fully recovered. Actual balances are not applied against the reserve until substantially all collection efforts have been exhausted. At December 31, 2007 and 2006, EAC had

ENCORE ACQUISITION COMPANY

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

$6.0 million and $2.3 million, respectively, of allowance for doubtful accounts. The following table summarizes the changes in the allowance for doubtful accounts for the periods indicated:

	Year Ended December 31, 2007	2006
	(In thousands)	
Allowance for doubtful accounts at January 1	$ 2,329	$ 347
Bad debt expense	5,816	1,970
Write off	(2,100)	(20)
Other		32
Allowance for doubtful accounts at December 31	$ 6,045	$ 2,329

Inventory

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

	December 31, 2007	2006
	(In thousands)	
Materials and supplies	$ 11,567	$ 11,784
Oil in pipelines	4,690	6,386
Total inventory	$ 16,257	$ 18,170

Properties and Equipment

Oil and Natural Gas Properties. EAC adheres to Statement of Financial Accounting Standards (SFAS) No. 19, *Financial Accounting and Reporting by Oil and Gas Producing Companies* (SFAS 19), utilizing the successful efforts method of accounting for its oil and natural gas properties. 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 a non-cash adjustment to net income in the Operating activities section of EAC s Consolidated Statements of Cash Flows in the period in which the determination is made. If an exploratory well finds reserves but they cannot be classified as proved, EAC will 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 EAC is making sufficient progress towards assessing the reserves and the operating viability of the project. If subsequently it is determined that neither of these conditions continue to exist, all previously capitalized costs associated with the exploratory well are expensed and shown as a non-cash adjustment to net income 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 would be classified as development or exploratory based on whether it is in a proved or unproved reservoir for determination of capital or expense. Expenditures for repairs and maintenance to sustain or increase production from the existing producing reservoir are charged to expense as incurred. Expenditures

ENCORE ACQUISITION COMPANY

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

to recomplete a current well in a different unproved reservoir are capitalized pending determination that economic reserves have been added. If the recompletion is not successful, the expenditures 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. Expenditures 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 total proved developed reserves or proved reserves, as applicable. Natural gas volumes are converted to equivalent barrels of oil (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 the accumulated depletion, depreciation, and amortization (DD&A) reserve.

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 quarter.

In accordance with SFAS No. 144, *Accounting for the Impairment or Disposal of Long-Lived Assets* , an impairment of capitalized costs of long-lived assets to be held and used, including proved oil and natural gas properties, must be assessed 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 it is recognized to the extent that the carrying value exceeds fair value. Expected future net cash flows are based on existing proved reserve and production information and pricing assumptions that management believes are reasonable. Any impairment charge incurred is expensed and reduces the recorded basis in the asset pool.

Unproved properties, the majority of the costs 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 an impairment, a loss is recognized by providing a valuation allowance at the level consistent with 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 over the average life of the lease.

ENCORE ACQUISITION COMPANY

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

	December 31, 2007	December 31, 2006
	(In thousands)	
Proved leasehold costs	$ 1,346,516	$ 796,932
Wells and related equipment Completed	1,408,512	1,193,939
Wells and related equipment In process	90,748	43,043
Total proved properties	$ 2,845,776	$ 2,033,914

Other Property and Equipment. Other property and equipment is carried at cost. Depreciation is recognized on a straight-line basis over estimated useful lives, which range from three to ten years. Leasehold improvements are capitalized and depreciated over the remaining term of the lease, which currently is through 2013 for EAC s corporate headquarters. Gains or losses from the disposal of other property and equipment are recognized in the period realized and included in Other operating expense of EAC s Consolidated Statements of Operations.

Goodwill

Goodwill represents the excess of the purchase price over the estimated fair value of the net assets acquired in business combinations. EAC assesses goodwill for impairment on an annual basis or whenever indicators of impairment exist. EAC performed its annual impairment test on December 31, 2007, and determined that no indicators of impairment existed. If indicators of impairment are determined to exist, EAC would recognize an impairment charge for any amount by which the carrying value of goodwill exceeds the implied fair value of the goodwill. The goodwill test is performed at the reporting unit level. EAC has determined that it has two reporting units: EAC Standalone and ENP. All goodwill has been allocated to the EAC Standalone reporting unit.

Asset Retirement Obligations

SFAS No. 143, *Accounting for Asset Retirement Obligations* requires that the fair value of a liability for an asset retirement obligation be recognized 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 EAC s oil and natural gas properties at its discounted fair value. The liability is then accreted up by recording expense each period until it is settled or the well is sold, at which time the liability is reversed. Estimates are based on historical experience in plugging and abandoning wells and estimated remaining lives of those wells based on reserve estimates. EAC does not provide for a market risk premium associated with asset retirement obligations because a reliable estimate cannot be determined. See Note 5. Asset Retirement Obligations for additional information.

Stock-Based Compensation

On January 1, 2006, EAC adopted the provisions of SFAS No. 123 (revised 2004), *Share-Based Payment* (SFAS 123R) using the modified prospective method. SFAS 123R is a revision of SFAS No. 123, *Accounting for Stock-Based Compensation* (SFAS 123) and supersedes Accounting Principles Board (APB) Opinion No. 25, *Accounting for Stock Issued to Employees* (APB 25). SFAS 123R eliminates the option of using the intrinsic value method of accounting previously available under APB 25 and requires companies to recognize in the financial statements the cost of employee services received in exchange for awards of equity instruments based on the grant date fair value of those awards. Under the modified

ENCORE ACQUISITION COMPANY

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

prospective method, compensation cost is recognized in the financial statements beginning with the effective date, based on the requirements of SFAS 123R, for all share-based payments granted after that date, and for all unvested awards granted prior to the effective date of SFAS 123R. EAC continues to utilize a standard option pricing model (i.e., Black-Scholes) to measure the fair value of employee stock options under SFAS 123R. Under SFAS 123R, the pro forma disclosures previously permitted under SFAS 123 are no longer an alternative to financial statement recognition.

SFAS 123R 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.

Prior to the adoption of SFAS 123R, employee stock options and restricted stock awards were accounted for under the provisions of APB 25, which resulted in no compensation expense being recorded for stock options, since all options that were granted to employees or non-employee directors had an exercise price equal to or above EAC s common stock price on the grant date. However, expense was recorded related to restricted stock granted to employees. Compensation expense associated with awards to employees who were eligible for retirement was recognized over the explicit service period of the award under APB 25. Compensation expense for such awards that are granted subsequent to the adoption of SFAS 123R are fully expensed on the date of grant. If EAC had recognized compensation expense at the time an employee became eligible for retirement and had satisfied all service requirements, non-cash stock-based compensation expense would have increased by $1.0 million in 2005.

During 2005, if compensation expense for stock-based awards had been accounted for under the provisions of SFAS 123R, EAC s net income and net income per share would have been as follows on a pro forma basis (in thousands, except per share amounts):

As Reported:		
Non-cash stock-based compensation, net of tax	$	2,483
Net income	$	103,425
Basic net income per share	$	2.12
Diluted net income per share	$	2.09
Pro Forma:		
Non-cash stock-based compensation, net of tax	$	3,091
Net income	$	102,817
Basic net income per share	$	2.11
Diluted net income per share	$	2.08

Major Customers

In 2007, Eighty-Eight Oil accounted for 14 percent of total sales of production, all of which is reported on the EAC Standalone segment. Prior to 2007, segment reporting was not applicable to EAC as ENP did not exist. In 2006, Shell Trading Company and ConocoPhillips accounted for 15 percent and 12 percent, respectively, of total sales of production. In 2005, Shell Trading Company, Eighty-Eight Oil, BP, and Chevron Corporation accounted for 26 percent, 16 percent, 14 percent, and 10 percent, respectively, of total sales of production.

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 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.

Revenue Recognition

Revenues are recognized as oil and natural gas is produced and sold, net of royalties and net profits interest payments. Natural gas revenues are also reduced by any processing and other fees paid 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 EAC s actual sales of natural gas rather than EAC s share of natural gas production. Royalties, net profits interests, and severance taxes are paid 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 price for those properties are estimated and recorded as Accounts receivable in the accompanying Consolidated Balance Sheets. If EAC s overproduced imbalance position (i.e., EAC has cumulatively been over-allocated production) is greater than EAC s share of remaining reserves, EAC records a liability for the excess at period-end prices. EAC does not recognize revenue for the production in tanks, oil marketed on behalf of joint owners in EAC s properties, or oil that resides in pipelines prior to delivery to the purchaser. EAC s net oil inventories in pipelines were 124,410 Bbls and 146,284 Bbls at December 31, 2007 and 2006, respectively. Natural gas imbalances at December 31, 2007 and 2006, were 128,856 million British thermal units (MMBtu) and 188,757 MMBtu under-delivered to EAC, respectively.

Marketing Revenues and Expenses and Buy/Sell Transactions

In 2006, EAC purchased third-party oil Bbls from counterparties other than to whom the Bbls were sold for aggregation and sale with its own equity production in various markets. These purchases assisted EAC in marketing its production by decreasing its dependence on individual markets. These activities allowed EAC to aggregate larger volumes, facilitated its efforts to maximize the prices it receives for production, provided for a greater allocation of future pipeline capacity in the event of curtailments, and enabled it to reach other markets. In 2007, EAC discontinued purchasing oil from third party companies as market conditions changed and historical pipeline space was realized. Implementing this change in direction allowed EAC to focus on the marketing of its own equity production, leveraging newly gained pipeline space, and on delivering oil to various newly developed markets in an effort to maximize netback value to the wellhead.

Marketing revenues derived from sales of oil purchased from third parties is recognized when persuasive evidence of a sales arrangement exists, delivery has occurred, the sales price is fixed or determinable, and collectibility is reasonably assured. Marketing expenses includes the cost of oil volumes purchased from third parties, as well as, transportation charges related to the purchased volumes, mostly in the form of pipeline tariffs. As EAC takes title to the oil and has risks and rewards of ownership, these transactions are presented gross in the Consolidated Statements of Operations, unless they meet the criteria for netting as outlined in EITF Issue No. 04-13, *Accounting for Purchases* *and Sales of Inventory with the Same Counterparty* (EITF 04-13). Prior to 2006, marketing activities were not material.

EITF 04-13 requires that two or more inventory purchase and sale transactions with the same counterparty that are entered into in contemplation of one another be viewed as a single exchange transaction and netted in accordance with the provisions of APB Opinion No. 29, *Accounting for Nonmonetary Transactions* . These types of transactions are commonly referred to as Buy/Sell transactions in the oil and gas industry. The net

ENCORE ACQUISITION COMPANY

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

gain/loss from Buy/Sell transactions with produced oil volumes is recorded as an adjustment to Oil revenues in the accompanying Consolidated Statements of Operations. The net gain/loss from Buy/Sell transactions with oil volumes purchased from third parties is recorded as an adjustment to Marketing revenues in the accompanying Consolidated Statements of Operations.

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.

Commodity Derivatives and Related Activities

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 forward derivative or option contracts with large financial institutions.

During July 2006, EAC elected to discontinue hedge accounting prospectively for all remaining commodity derivative contracts which were previously accounted for as hedges. The net deferred loss in Accumulated Other Comprehensive Loss (AOCL) at the time of dedesignation is being amortized to oil and natural gas revenues over the original term of the contracts. AOCL at December 31, 2007 of $1.8 million is expected to be reclassified to earnings by June 30, 2008. The amortization of these amounts is included in oil and natural gas revenues with the revenues from the hedged production. All mark-to-market gains and losses from July 2006 forward are recognized in earnings through Derivative fair value loss (gain) in the accompanying Consolidated Statements of Operations rather than deferring such amounts in AOCL.

Prior to the discontinuation of hedge accounting in July 2006, if a derivative qualified for hedge accounting, depending on the nature of the hedge, changes in fair value could have been offset against the change in fair value of the hedged item through earnings or recognized in other comprehensive income until such time as the hedged item was recognized in earnings. To qualify for cash flow hedge accounting, the cash flows from the hedging instrument had to be highly effective in offsetting changes in cash flows of the hedged item. In addition, all hedging relationships had to be designated, documented, and reassessed periodically. The effective portion of changes in the fair value of these contracts was deferred, until the hedged production occurred, in AOCL, rather than recognized currently in earnings. Any ineffective portion of changes in the fair value of these contracts was recognized in earnings through Derivative fair value loss (gain) in the accompanying Consolidated Statements of Operations. If a derivative did not qualify for hedge accounting, it was adjusted to fair value through earnings.

Comprehensive Income

Comprehensive income includes net income and other comprehensive income, which includes the amortization of deferred hedge losses, net of tax, on derivative financial instruments. EAC has elected to show comprehensive income as part of its Consolidated Statements of Stockholders Equity and Comprehensive Income rather than in its Consolidated Statements of Operations.

Use of Estimates

Preparing financial statements in conformity with accounting principles generally accepted in the United States requires management to make certain estimations and assumptions that affect the reported amounts of

ENCORE ACQUISITION COMPANY

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

assets and liabilities and disclosure of contingent assets and liabilities in the consolidated financial statements and the reported amounts of revenues and expenses. 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 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. Future changes in the assumptions used could have a significant impact on reported results in future periods.

New Accounting Pronouncements

SFAS No. 157, Fair Value Measurement (SFAS 157)

In September 2006, the FASB issued SFAS 157. SFAS 157 standardizes the definition of fair value, establishes a framework for measuring fair value in generally accepted accounting principles and expands disclosures related to the use of fair value measures in financial statements. SFAS 157 applies whenever other standards require (or permit) assets or liabilities to be measured at fair value, but does not require any new fair value measurements. SFAS 157 is prospectively effective for financial assets and liabilities for financial statements issued for fiscal years beginning after November 15, 2007, and interim periods within those fiscal years. On February 12, 2008, the FASB issued FASB Staff Position (FSP) 157-2 (FSP 157-2) which delays the effective date of SFAS 157 for one year, for all nonfinancial assets and liabilities, except those that are recognized or disclosed at fair value in the financial statements on a recurring basis (at least annually). EAC has elected a partial deferral of SFAS 157 for all instruments within the scope of FSP 157-2 including but not limited to its asset retirement obligations and indefinite lived assets. EAC will continue to evaluate the impact of SFAS 157 on these instruments during the deferral period. SFAS 157, as it relates to financial assets and liabilities, is effective beginning in the first quarter of 2008. EAC does not currently expect the adoption of SFAS 157 to have a material impact on its results of operations or financial condition, however, the fair value of EAC s derivative instruments has always been dependent on multiple variables that can be volatile and unpredictable, therefore, any impact of adopting SFAS 157 will not be known for certain until the end of each reporting period.

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

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

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

In April 2007, the FASB issued FSP FIN 39-1. FSP FIN 39-1 amends FIN No. 39, *Offsetting of Amounts Related to Certain Contracts* (FIN 39), to permit a reporting entity that is party to a master netting arrangement to offset the fair value amounts recognized for the right to reclaim cash collateral (a receivable) or the obligation to return cash collateral (a payable) against fair value amounts recognized for derivative instruments that have been offset under the same master netting arrangement in accordance with FIN 39. FSP

ENCORE ACQUISITION COMPANY

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

FIN 39-1 is effective for fiscal years beginning after November 15, 2007. EAC does not expect the adoption of FSP FIN 39-1 to have a material impact on its results of operations or financial condition.

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

In December 2007, the FASB issued SFAS 141R. SFAS 141R is a revision of SFAS No. 141, *Business Combinations* (SFAS 141). SFAS 141R amends SFAS 141 by requiring an acquirer to recognize: (i) the assets acquired, liabilities assumed, and any noncontrolling interest in the acquiree at fair value as of the acquisition date, (ii) a gain attributable to any negative goodwill in a bargain purchase, and (iii) an expense related to acquisition costs. SFAS 141R is effective for fiscal years beginning on or after December 15, 2008. EAC does not expect the adoption of SFAS 141R to have a material impact on its current results of operations or financial condition. However, future results of operations or financial condition may be materially affected if EAC has a significant acquisition.

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

In December 2007, the FASB issued SFAS 160. SFAS 160 amends Accounting Research Bulletin No. 51, *Consolidated Financial Statements* (ARB 51) to establish accounting and reporting standards for the noncontrolling interest in a subsidiary and for the deconsolidation of a subsidiary. SFAS 160 is effective for fiscal years beginning on or after December 15, 2008. EAC expects the adoption of SFAS 141R to have a material impact on how it accounts for and discloses the noncontrolling interest in ENP. Minority interest in consolidated partnership in EAC s Consolidated Balance Sheets will be reflected as a component of stockholders equity and Minority interest in loss of consolidated partnership in EAC s Consolidated Statements of Operations will be moved to below net income.

Note 3. Acquisitions and Dispositions

2007 Acquisitions

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

The total purchase price for the Williston Basin assets was approximately $392.1 million, including transaction costs of approximately $1.3 million. The calculation of the total purchase price and the allocation

ENCORE ACQUISITION COMPANY

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

to the fair value of the Williston Basin assets acquired and liabilities assumed from Anadarko are as follows as of December 31, 2007 (in thousands):

Calculation of total purchase price:	
Cash paid to Anadarko	$ 390,728
Transaction costs	1,333
Total purchase price	$ 392,061
Allocation of purchase price to the fair value of net assets acquired:	
Proved properties, including wells and related equipment	$ 383,909
Unproved properties	16,134
Accounts receivable	3,008
Inventory	805
Total assets acquired	403,856
Current liabilities	8,289
Future abandonment cost and assumed liabilities	3,506
Total liabilities assumed	11,795
Fair value of net assets acquired	$ 392,061

On January 16, 2007, EAC entered into a purchase and sale agreement with certain subsidiaries of Anadarko to acquire oil and natural gas properties and related assets in the Big Horn Basin of Wyoming and Montana, which included oil and natural gas properties and related assets in or near the Elk Basin field in Park County, Wyoming and Carbon County, Montana and oil and natural gas properties and related assets in the Gooseberry field in Park County, Wyoming. Prior to closing, EAC assigned the rights and duties under the purchase and sale agreement relating to the Elk Basin assets to Encore Energy Partners Operating LLC (OLLC), a Delaware limited liability company and wholly owned subsidiary of ENP, and the rights and duties under the purchase and sale agreement relating to the Gooseberry assets to Encore Operating. The closing of the Big Horn Basin acquisition occurred on March 7, 2007 after which time the operations have been included with those of EAC.

The total purchase price for the Big Horn Basin assets was approximately $393.6 million, including transaction costs of approximately $1.3 million. The calculation of the total purchase price and the allocation

ENCORE ACQUISITION COMPANY

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

to the fair value of the Big Horn Basin assets acquired and liabilities assumed from Anadarko are as follows as of December 31, 2007 (in thousands):

Calculation of total purchase price:	
Cash paid to Anadarko	$ 392,289
Transaction costs	1,288
Total purchase price	$ 393,577
Allocation of purchase price to the fair value of net assets acquired:	
Proved properties, including wells and related equipment	$ 395,606
Intangibles	4,225
Accounts receivable	1,673
Other property and equipment	346
Total assets acquired	401,850
Current liabilities	1,300
Future abandonment cost and assumed liabilities	6,973
Total liabilities assumed	8,273
Fair value of net assets acquired	$ 393,577

Proved properties include the fair value of proved leasehold costs, lease and well equipment (including flue gas reinjection facilities used to maintain reservoir pressure by compressing and reinjecting the gas produced), and pipelines used primarily to transport production from the acquired fields. Natural gas liquids are produced as a byproduct of the flue gas tertiary recovery project and are sold at market prices. The revenues generated by these hydrocarbon liquids are included in Oil revenues in the accompanying Consolidated Statements of Operations. Third-party revenues and expenses related to the pipelines are included in Marketing revenues and Marketing expenses , respectively, in the accompanying Consolidated Statements of Operations.

EAC and ENP financed the acquisitions of the Big Horn Basin and Williston Basin assets through borrowings under their respective revolving credit facility. See Note 8. Long-Term Debt for additional discussion of EAC s and ENP s revolving credit facilities. See Note 15. Financial Statements of Subsidiary Guarantors for a discussion of EAC s guarantor and non-guarantor subsidiaries.

2007 Dispositions

On June 29, 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, which is included in Other operating expense in the accompanying Consolidated Statements of Operations. The disposed properties included certain properties in the Anadarko and Arkoma fields of Oklahoma. EAC retained a material oil and natural gas interest in other properties in these fields and remains active in those areas.

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

Table of Contents

ENCORE ACQUISITION COMPANY

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Pro Forma

The following unaudited pro forma condensed financial data was derived from the historical financial statements of EAC and from the accounting records of Anadarko to give effect to the Big Horn Basin and Williston Basin asset acquisitions and the Mid-Continent disposition as if they had occurred on January 1, 2005. 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 Big Horn Basin and Williston Basin asset acquisitions and the Mid-Continent disposition taken place as of the dates indicated and are not intended to be a projection of future results.

	Year Ended December 31,		
	2007	2006	2005
	(In thousands, except per share amounts)		
Pro forma total revenues	$ 749,659	$ 785,281	$ 621,858
Pro forma net income	$ 20,685	$ 100,702	$ 110,789
Pro forma net income per common share:			
Basic	$ 0.39	$ 1.94	$ 2.28
Diluted	$ 0.38	$ 1.91	$ 2.24

2005 Acquisitions

Williston Basin Acquisition. On September 8, 2005, EAC acquired oil and natural gas properties in the Williston Basin for a purchase price of approximately $28.6 million. The properties are concentrated primarily in the Crane Field in Montana and the Tracy Mountain Field in North Dakota.

Crusader Acquisition. On October 14, 2005, EAC purchased all of the outstanding capital stock of Crusader Energy Corporation (Crusader), a privately held, independent oil and natural gas company, for approximately $109.6 million, which includes cash paid to Crusader s former shareholders of approximately $79.1 million, the repayment of approximately $29.7 million of Crusader s debt, and transaction costs of approximately $0.7 million.

The acquired properties are located primarily in the western Anadarko Basin and the Golden Trend area of Oklahoma. Crusader s operating results are included in EAC s Consolidated Statements of Operations beginning in October 2005.

Table of Contents

ENCORE ACQUISITION COMPANY

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

The calculation of the total purchase price and the allocation to the fair value of net assets acquired from Crusader are as follows (in thousands):

Calculation of total purchase price:	
Cash paid to Crusader s former owners	$ 79,142
Crusader debt repaid	29,732
Transaction costs	707
Total purchase price	$ 109,581
Allocation of purchase price to the fair value of assets acquired:	
Cash	$ 18,592
Other current assets	3,362
Deferred taxes	1,997
Proved properties, including wells and related equipment	85,388
Unproved properties	6,863
Goodwill	22,698
Total assets acquired	138,900
Current liabilities	10,267
Other noncurrent liabilities	1,190
Deferred taxes	17,862
Total liabilities assumed	29,319
Fair value of net assets acquired	$ 109,581

The purchase price allocation resulted in approximately $22.7 million of goodwill primarily as the result of the difference between the fair value of acquired oil and natural gas properties and their lower carryover tax basis, which resulted in a net deferred tax liability of approximately $15.9 million. Management believes the goodwill will be recovered through operating synergies resulting from the close proximity of the properties acquired to EAC s other operations. None of the goodwill is deductible for income tax purposes.

Kerr-McGee Acquisition. On November 30, 2005, EAC acquired oil and natural gas properties from Kerr-McGee Corporation for a purchase price of approximately $101.4 million. The acquired properties are located in the Levelland-Slaughter, Howard Glasscock, Nolley-McFarland, and Hutex fields in West Texas and the Oakdale, Calumet, and Rush Springs fields in western Oklahoma.

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 results of operations or financial position.

ENCORE ACQUISITION COMPANY

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Leases

EAC leases office space and equipment that have remaining 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, 2007 (in thousands):

2008	$ 3,064
2009	2,900
2010	2,911
2011	2,900
2012	2,835
Thereafter	2,607
	$ 17,217

EAC s operating lease rental expense was approximately $5.3 million, $4.5 million, and $3.1 million in 2007, 2006, and 2005, respectively.

ExxonMobil

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

EAC will earn the right to participate in all fields by drilling a total of 24 commitment wells by the end of 2008. During the commitment phase, ExxonMobil will have the option to receive non-recourse advanced funds from EAC attributable to ExxonMobil s 70 percent working interest in each commitment well. Once a commitment well is producing, ExxonMobil will repay 95 percent of the advanced funds plus accrued interest assessed on the unpaid balance through EAC s monthly receipt of proceeds of oil and natural gas sales. As an alternative to receiving advanced funds during the commitment phase, ExxonMobil can elect to pay their share of capital costs for each well. After EAC has fulfilled its obligations under the commitment phase, EAC will be entitled to a 30 percent working interest in future drilling locations. EAC will have the right to propose and drill wells for as long as EAC is engaged in continuous drilling operations.

During 2007 and 2006, EAC advanced $37.7 million and $22.4 million, respectively, to ExxonMobil for its portion of capital related to drilling commitment wells, of which $51.7 million and $21.0 million remained outstanding at December 31, 2007 and 2006, respectively. At December 31, 2007, $12.3 million is included in Accounts receivable and $39.4 million is included in Long-term receivables on the accompanying Consolidated Balance Sheet based on when EAC expects repayment. At December 31, 2006, $3.0 million is included in Accounts receivable and $18.0 million is included in Long-term receivables on the accompanying Consolidated Balance Sheet. As of

December 31, 2007, EAC had 6 wells to drill in order to fulfill its commitment under the joint development agreement at a minimum cost of $1.0 million per well.

Note 5. Asset Retirement Obligations

EAC s primary asset retirement obligations relate to future plugging and abandonment expenses on oil and natural gas properties and related facilities disposal. As of December 31, 2007, EAC had $6.7 million held in an escrow account from which funds are released only for reimbursement of plugging and abandonment expenses on its Bell Creek property. This amount is included in long-term other assets in the accompanying Consolidated Balance Sheet. The following table summarizes the changes in future abandonment liability for

ENCORE ACQUISITION COMPANY

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

the periods indicated, the long-term portion of which is recorded in Future abandonment cost and the current portion of which is included in Other current liabilities on the accompanying Consolidated Balance Sheets:

	Year Ended December 31, 2007	2006
	(In thousands)	
Future abandonment liability at January 1	$ 19,841	$ 14,430
Acquisition of properties	8,251	785
Disposition of properties	(959)	
Wells drilled	145	147
Accretion of discount	1,145	743
Plugging and abandonment costs incurred	(1,655)	(1,466)
Revision of estimates	1,311	5,202
Future abandonment liability at December 31	$ 28,079	$ 19,841

Note 6. Capitalization of Exploratory Well Costs

EAC follows FSP No. 19-1 *Accounting for Suspended Well Costs* (FSP 19-1), which permits the continued 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, 2007	2006	2005
		(In thousands)	
Beginning balance at January 1	$ 13,048	$ 6,560	$ 3,242
Additions to capitalized exploratory well costs pending the determination of proved reserves	19,479	13,048	6,560
Reclassification to proved property and equipment based on the determination of proved reserves	(9,390)	(1,457)	(996)
Capitalized exploratory well costs charged to expense	(3,658)	(5,103)	(2,246)
Total	$ 19,479	$ 13,048	$ 6,560

All of the capitalized exploratory well costs at December 31, 2007 related to wells in progress or wells for which drilling had been completed for less than one year.

ENCORE ACQUISITION COMPANY

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Note 7. Other Current Liabilities

Other current liabilities consisted of the following as of the dates indicated:

	December 31, 2007	December 31, 2006
	(In thousands)	
Net profits payable	$ 3,996	$ 1,178
Natural gas imbalances	408	3,173
Income taxes payable	2,789	1,247
Accrued employee bonuses	8,431	5,665
Current portion of future abandonment liability	708	636
Liabilities assumed at acquisition	2,228	
Other	2,583	847
Total	$ 21,143	$ 12,746

Note 8. Long-Term Debt

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

	December 31, 2007	December 31, 2006
	(In thousands)	
Revolving credit facilities	$ 526,000	$ 68,000
6.25% Notes	150,000	150,000
6.0% Notes, net of unamortized discount of $4,440 and $4,892, respectively	295,560	295,108
7.25% Notes, net of unamortized discount of $1,323 and $1,412, respectively	148,676	148,588
Total	$ 1,120,236	$ 661,696

Senior Subordinated Notes

6.25% Notes. On April 2, 2004, EAC issued $150 million of its 6.25% Senior Subordinated Notes due April 15, 2014 (the 6.25% Notes). EAC received net proceeds of approximately $146.4 million. Interest on the 6.25% Notes is due semi-annually on April 15 and October 15.

6.0% Notes. On July 13, 2005, EAC issued $300 million of its 6.0% Senior Subordinated Notes due July 15, 2015 (the 6.0% Notes). EAC received net proceeds of approximately $294.5 million from the private placement. Interest on the 6.0% Notes is due semi-annually on January 15 and July 15.

7.25% Notes. On November 23, 2005, EAC issued $150 million of its 7.25% Senior Subordinated Notes due December 1, 2017 (the 7.25% Notes and together with the 6.25% Notes and the 6.0% Notes, the Notes). EAC received net proceeds of approximately $148.5 million. Interest on the 7.25% Notes is due semi-annually on June 1 and December 1.

As of December 31, 2007 certain of EAC s subsidiaries are subsidiary guarantors of the Notes. The subsidiary guarantors may without restriction transfer funds to EAC in the form of cash dividends, loans, and advances. See Note 15. Financial Statements of Subsidiary Guarantors for additional discussion.

ENCORE ACQUISITION COMPANY

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

The indentures governing the 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, 2007, EAC was in compliance with all covenants of the Notes.

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

Revolving Credit Facilities

Encore Acquisition Company Senior Secured Credit Agreement

On March 7, 2007, EAC entered into a five-year amended and restated credit agreement (the EAC Credit Agreement) with a bank syndicate comprised of Bank of America, N.A. and other lenders. 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. As of December 31, 2007, the borrowing base was $870 million.

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

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

Ratio of Total Outstanding Borrowings to Borrowing Base	Applicable Margin for Eurodollar Loans	Applicable Margin for Base Rate Loans
Less than .50 to 1	1.000%	0.000%
Greater than or equal to .50 to 1 but less than .75 to 1	1.250%	0.000%

Greater than or equal to .75 to 1 but less than .90 to 1	1.500%	0.250%
Greater than or equal to .90 to 1	1.750%	0.500%

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

As of December 31, 2007, there were $478.5 million of outstanding borrowings and $371.5 million of borrowing capacity under the EAC Credit Agreement. As of December 31, 2007, there were $20 million

ENCORE ACQUISITION COMPANY

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

outstanding letters of credit, all of which related to EAC s joint development agreement with ExxonMobil. See Note 4. Commitments and Contingencies for additional discussion of this agreement. Any outstanding letters of credit reduce the availability under the EAC Credit Agreement. Borrowings under the EAC Credit Agreement may be repaid from time to time without penalty.

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

a prohibition against incurring debt, subject to permitted exceptions;

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

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

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

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

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

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

The EAC Credit Agreement contains customary events of default. If an event of default occurs and is continuing, lenders with a majority of the aggregate commitments may require Bank of America, N.A. to declare all amounts outstanding under the EAC Credit Agreement to be immediately due and payable. As of December 31, 2007, EAC was in compliance with all covenants of the EAC Credit Agreement.

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

Ratio of Total Outstanding Borrowings to Borrowing Base	**Commitment Fee Percentage**
Less than .50 to 1	0.250%
Greater than or equal to .50 to 1 but less than .75 to 1	0.300%
Greater than or equal to .75 to 1 but less than .90 to 1	0.375%

Greater than or equal to .90 to 1	0.375%

Encore Energy Partners Operating LLC Credit Agreement

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

The aggregate amount of the commitments of the lenders under the OLLC Credit Agreement is $300 million. Availability under the OLLC Credit Agreement is subject to a borrowing base, which is

ENCORE ACQUISITION COMPANY

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

redetermined semi-annually and upon requested special redeterminations. As of December 31, 2007, the borrowing base was $145 million.

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

As of December 31, 2007, there were $47.5 million of outstanding borrowings and $97.4 million of borrowing capacity under the OLLC Credit Agreement. As of December 31, 2007, there were $0.1 million outstanding letters of credit. Any outstanding letters of credit reduce the availability under the OLLC Credit Agreement. Borrowings under the OLLC Credit Agreement may be repaid from time to time without penalty.

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

- a prohibition against incurring debt, subject to permitted exceptions;
- a prohibition against purchasing or redeeming capital stock, or prepaying indebtedness, subject to permitted exceptions;
- a restriction on creating liens on the assets of ENP, OLLC and its restricted subsidiaries, subject to permitted exceptions;
- restrictions on merging and selling assets outside the ordinary course of business;
- restrictions on use of proceeds, investments, transactions with affiliates, or change of principal business;
- a provision limiting oil and natural gas hedging transactions (other than puts) to a volume not exceeding 75 percent of anticipated production from proved producing reserves;
- a requirement that OLLC maintain a ratio of consolidated current assets to consolidated current liabilities of not less than 1.0 to 1.0;
- a requirement that OLLC maintain a ratio of consolidated EBITDA (as defined in the OLLC Credit Agreement) to the sum of consolidated net interest expense plus letter of credit fees of not less than 1.5 to 1.0;
- a requirement that OLLC maintain a ratio of consolidated EBITDA (as defined in the OLLC Credit Agreement) to consolidated senior interest expense of not less than 2.5 to 1.0; and

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

The OLLC Credit Agreement contains customary events of default. If an event of default occurs and is continuing, lenders with a majority of the aggregate commitments may require Bank of America, N.A. to declare all amounts outstanding under the OLLC Credit Agreement to be immediately due and payable. At December 31, 2007, OLLC was in compliance with all covenants of the OLLC Credit Agreement, as amended.

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

ENCORE ACQUISITION COMPANY

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Long-Term Debt Maturities

The following table illustrates long-term debt maturities as of December 31, 2007:

	Payments Due by Period (In thousands)				
	Total	2008	2009-2010	2011-2012	Thereafter
6.25% Notes	$ 150,000	$	$	$	$ 150,000
6.0% Notes	300,000				300,000
7.25% Notes	150,000				150,000
Revolving credit facilities	526,000			526,000	
Total	$ 1,126,000	$	$	$ 526,000	$ 600,000

Consolidated cash payments for interest were $82.6 million, $46.4 million, and $24.2 million during 2007, 2006, and 2005, respectively.

During 2007, 2006, and 2005, the weighted average interest rate for total indebtedness, including the Notes, the revolving credit facilities, letters of credit, and related miscellaneous fees was 6.9 percent, 6.1 percent, and 6.8 percent, respectively.

Note 9. Taxes

Income Taxes

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

	Year Ended December 31, (In thousands)		
	2007	2006	2005
Federal:			
Current	$ (1,888)	$ (3,785)	$ 2,084
Deferred	(11,229)	(48,327)	(53,147)
Total federal	(13,117)	(52,112)	(51,063)
State, net of federal benefit/expense:			
Current		(401)	
Deferred	(1,359)	(2,893)	(2,885)

Total state	(1,359)	(3,294)	(2,885)
Income tax provision(a)	$ (14,476)	$ (55,406)	$ (53,948)

(a) These amounts do not include EAC s excess tax benefit related to stock option exercises and vesting of restricted stock, which was recorded directly to additional paid-in capital, of $1.3 million and $1.4 million during 2006 and 2005, respectively.

Table of Contents

ENCORE ACQUISITION COMPANY

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

	Year Ended December 31, 2007	2006	2005
		(In thousands)	
Income before income taxes	$ 31,631	$ 147,804	$ 157,373
Tax at statutory rate	$ (11,071)	$ (51,731)	$ (55,081)
State income taxes, net of federal benefit/expense	(716)	(3,440)	(2,885)
Enactment of the Texas margin tax		(1,062)	
Change in estimated future state tax rate	(495)	1,208	363
Nondeductible deferred compensation	(1,963)		
Section 43 credits			3,227
Permanent and other	(231)	(381)	428
Income tax provision	$ (14,476)	$ (55,406)	$ (53,948)

The Enhanced Oil Recovery credits available under Section 43 were fully phased out beginning in the 2006 tax year due to high oil prices in 2005. Therefore, no credits were generated during 2007 or 2006. A Texas franchise tax reform measure signed into law in May 2006, caused the Texas franchise tax to be applicable to numerous types of entities that previously were not subject to the tax, including several of EAC s subsidiaries. EAC adjusted its net deferred tax balances using the new higher marginal tax rate it expects to be effective when those deferred taxes reverse resulting in a charge of $1.1 million during 2006.

Cash income tax payments were $0.3 million, $0.5 million, and $0.2 million during 2007, 2006, and 2005, respectively. EAC recognized in equity a benefit resulting from the reduction in income taxes payable related to the exercise of employee stock options and the vesting of restricted stock of $1.3 million and $1.4 million in 2006 and 2005, respectively.

Table of Contents

ENCORE ACQUISITION COMPANY

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

	December 31, 2007	December 31, 2006
	(In thousands)	
Current:		
Assets:		
Unrealized hedge loss in AOCL	$ 1,071	$ 20,049
Derivative fair value loss	15,442	4,062
Other	3,907	867
Total current deferred tax assets	$ 20,420	$ 24,978
Long-term:		
Assets:		
Alternative minimum tax carryforward	$ 2,676	$ 2,394
Unrealized hedge loss in AOCL		1,069
Derivative fair value loss	10,775	2,606
Section 43 credits	13,227	13,227
Net operating loss carryforward	23,806	1,013
Other	6,789	4,602
Total long-term deferred tax assets	57,273	24,911
Liabilities:		
Book basis of oil and natural gas properties in excess of tax basis	370,187	307,736
Net long-term deferred tax liability	$ 312,914	$ 282,825

At December 31, 2007, EAC had net operating loss (NOL) carryforwards and Section 43 credits related to federal and state income taxes, which are available to offset future regular taxable income, if any. Additionally, EAC has alternative minimum tax credits, which are available to reduce our alternative minimum taxable income in the future. If unused, these carryforwards and credits will expire as follows:

Expiration Date	Federal NOL	Federal AMT NOL	Federal Sec. 43 Cr.	State NOL
	(In thousands)			
2012	$	$	$	$ 53

2014				817
2022	21,913			82
2023			1,082	
2024			6,125	2
2025			6,020	482
2026				152
2027				305
Indefinite		2,676		
	$ 21,913	$ 2,676	$ 13,227	$ 1,893

99

ENCORE ACQUISITION COMPANY

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

EAC believes that it is more likely than not that these NOL carryforwards and credits will all offset future taxable income prior to their expiration. Therefore, a valuation allowance against these deferred tax assets in not considered necessary.

On January 1, 2007, EAC adopted the provisions of FIN No. 48, *Accounting for Uncertainty in Income Taxes an Interpretation of FASB Statement No. 109* (FIN 48). FIN 48 clarifies the accounting for uncertainty in income taxes recognized in an entity s financial statements in accordance with SFAS No. 109, *Accounting for Income Taxes* . FIN 48 prescribes a recognition threshold and measurement attribute for the financial statement recognition and measurement of a tax position taken or expected to be taken in a tax return. 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 2003.

EAC performed its evaluation of tax positions and determined that the adoption of FIN 48 did not have a material impact on its financial condition, results of operations, or cash flows. This evaluation was a review of 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.

Based on this evaluation, EAC did not identify any tax positions that did not meet the highly certain positions threshold. As a result, no additional tax expense, interest, or penalties have been accrued as a result of the review.

EAC includes interest assessed by the taxing authorities in Interest expense and penalties related to income taxes in Other expense on its Consolidated Statements of Operations. For 2007, 2006, and 2005, EAC recorded only a nominal amount of interest and penalties on certain tax positions.

Taxes Other than Income Taxes

Taxes other than income taxes were comprised of the following for the periods indicated:

	Year Ended December 31,		
	2007	2006	2005
	(In thousands)		
Production and severance taxes	$ 65,145	$ 43,458	$ 41,195
Ad valorem taxes	9,440	6,322	4,406
Franchise, payroll, and other taxes	2,263	1,745	1,246
Total	$ 76,848	$ 51,525	$ 46,847

ENCORE ACQUISITION COMPANY

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Note 10. Stockholders Equity

Public Offering of Common Stock

In April 2006, EAC issued 4,000,000 shares of its common stock at a price of $32.00 per share. The net proceeds of approximately $127.1 million were used to (i) reduce outstanding borrowings under EAC s revolving credit facility, (ii) invest in oil and natural gas activities, and (iii) pay general corporate expenses.

Shelf Registration Statement on Form S-3

On June 30, 2004, EAC filed a shelf registration statement on Form S-3 with the Securities Exchange Commission (SEC). Using this process, EAC may offer common stock, preferred stock, senior debt, and/or subordinated debt in one or more offerings with a total initial offering price of up to $500 million. On November 23, 2005, EAC issued $150 million of 7.25% Notes under the shelf.

Stock Split

On June 15, 2005, EAC announced that its Board of Directors (the Board) approved a three-for-two split of EAC s outstanding common stock in the form of a stock dividend. The dividend was distributed on July 12, 2005, to stockholders of record at the close of business on June 27, 2005 (the Record Date). In lieu of issuing fractional shares, EAC paid cash for such fractional shares based on the closing price of the common stock on the Record Date. All share amounts for 2004 have been retroactively adjusted to reflect this change in capital structure.

Stock Option Exercises and Restricted Stock Vestings

During 2007, 2006, and 2005, employees of EAC exercised 128,709 options, 178,174 options, and 137,413 options, respectively, for which EAC received proceeds of $1.6 million, $2.3 million, and $1.5 million in 2007, 2006, and 2005, respectively. During 2007, 2006, and 2005, employees elected to satisfy minimum tax withholding obligations related to the vesting of restricted stock by allowing EAC to withhold 38,978 shares, 24,362 shares, and 18,298 shares of common stock, respectively, which are accounted for as treasury stock until they are formally retired.

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, 2007 or 2006. EAC has no current plans to issue any shares of preferred stock.

Stock Repurchase Program

During December 2007, EAC announced that the Board had approved a new share repurchase program authorizing the purchase of up to $50 million of EAC s common stock. As of December 31, 2007, EAC had not repurchased any of its common shares under this program.

Gain on Sale of ENP Common Units

During 2007, EAC reclassified $77.6 million from Minority interest in consolidated partnership to Additional paid-in capital on the accompanying Consolidated Balance Sheet to recognize the gain on sale of ENP s common units in 2007.

ENCORE ACQUISITION COMPANY

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Note 11. Earnings Per Share (EPS)

Under SFAS No. 128, *Earnings Per Share* , EAC must report basic EPS, which excludes the effect of potentially dilutive securities, and diluted EPS, which includes the effect of all potentially dilutive securities, based on the weighted average common shares outstanding for the period. The following table reflects EPS computations for the periods indicated:

	Year Ended December 31,		
	2007(b)	2006	2005
	(In thousands, except per share data)		
Numerator:			
Net income	$ 17,155	$ 92,398	$ 103,425
Denominator:			
Denominator for basic EPS:			
Weighted average shares outstanding	53,170	51,865	48,682
Effect of dilutive options and diluted restricted stock(a)	974	871	840
Denominator for diluted EPS	54,144	52,736	49,522
Net income per common share:			
Basic	$ 0.32	$ 1.78	$ 2.12
Diluted	$ 0.32	$ 1.75	$ 2.09

(a) For 2007 and 2006, options to purchase 121,651 and 103,856 shares of common stock, respectively, were outstanding but not included in the above calculation of diluted EPS because their effect would be antidilutive. There were no antidilutive options for 2005. For 2007, there were 59,865 shares of restricted stock that were not included in the above calculation of diluted EPS because their effect would have been antidilutive. There were no antidilutive shares of restricted stock for 2006 or 2005.

(b) For 2007 diluted EPS, EAC considered the impact of the conversion of vested management incentive units held by certain executive officers of ENP. The conversion of the management incentive units into limited partner units of ENP would result in reducing EAC s share of ENP s earnings. Since ENP incurred a net loss for 2007, the impact of this conversion would be antidilutive and was thus excluded from the above calculation.

Note 12. Employee Benefit Plans

401(k) Plan

EAC made contributions to the Encore Acquisition Company 401(k) Plan (the EAC 401(k) Plan), which is a voluntary and contributory plan for eligible employees based on a percentage of employee contributions, of $2.2 million,

$1.1 million, and $0.8 million during 2007, 2006, and 2005, respectively. The EAC 401(k) Plan currently does not allow employees to invest in securities of EAC. Effective February 1, 2007, EAC increased the percentage of employee contributions that will be matched under the EAC 401(k) Plan.

Incentive Stock Plans

During 2000, the Board and stockholders approved the 2000 Incentive Stock Plan (the EAC Plan). The EAC Plan was amended and restated effective March 18, 2004. The purpose of the EAC Plan is to attract, motivate, and retain selected employees of EAC and to provide EAC with the ability to provide incentives more directly linked to the profitability of the business and increases in shareholder value. All directors and full-time regular employees of EAC and its subsidiaries and affiliates are eligible to be granted awards under

Table of Contents

ENCORE ACQUISITION COMPANY

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

the EAC Plan. The total number of shares of common stock reserved for issuance pursuant to the EAC Plan is 4,500,000. As of December 31, 2007, there were 859,508 shares available for issuance under the EAC Plan. Shares delivered or withheld for payment of the exercise price of an option, shares withheld for payment of tax withholding, or shares subject to options or other awards which expire or are terminated and restricted shares that are forfeited will again become available for issuance under the EAC Plan. The EAC Plan provides for the granting of cash awards, incentive stock options, non-qualified stock options, restricted stock, and stock appreciation rights at the discretion of the Compensation Committee of the Board. The Board also has a Restricted Stock Award Committee whose sole member is Jon S. Brumley, EAC s Chief Executive Officer and President. The Restricted Stock Award Committee may grant up to 25,000 shares of restricted stock on an annual basis to non-executive employees at its discretion.

The EAC Plan contains the following individual limits:

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

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

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

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

The non-cash stock-based compensation cost related to the EAC Plan recorded in the accompanying Consolidated Statements of Operations for 2007, 2006, and 2005 was $9.2 million, $9.0 million, and $4.0 respectively. The income tax benefit of the non-cash stock-based compensation cost related to the EAC Plan recorded in the accompanying Consolidated Statements of Operations for 2007, 2006, and 2005 was $3.4 million, $3.2 million, and $1.5 million, respectively. During 2007 and 2006, EAC also capitalized $1.3 million and $1.1 million, respectively, of non-cash stock-based compensation cost as a component of Properties and equipment in the accompanying Consolidated Balance Sheets. Non-cash stock-based compensation expense has been allocated to lease operations expense, general and administrative expense, and exploration expense based on the allocation of the respective employees cash compensation.

See Note 16. ENP for a discussion of ENP s unit-based compensation plan.

Stock Options. The fair value of options granted during 2007, 2006, and 2005 was estimated on the grant date using a Black-Scholes option valuation model based on the assumptions noted in the following table. The expected volatility is based on the historical volatility of EAC s common stock for a period of time commensurate with the expected term of the options. EAC uses the simplified method prescribed by SEC Staff Accounting Bulletin No. 107 to estimate the expected term of the options, which is calculated as the average midpoint between each vesting date and the life of the option. The risk-free interest rate is based on

103

ENCORE ACQUISITION COMPANY

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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.

	Year Ended December 31, 2007	2006	2005
Expected volatility	35.7%	42.8%	46.0%
Expected dividend yield	0.0%	0.0%	0.0%
Expected term (in years)	6.0	6.0	6.0
Risk-free interest rate	4.8%	4.6%	3.7%

The following table summarizes the changes in the number of outstanding options and their related weighted average strike prices for the periods indicated:

	Year Ended December 31, 2007				2006		2005	
	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	1,337,118	$ 14.44			1,440,812	$ 13.20	1,520,586	$ 12.00
Granted	200,059	25.73			122,890	31.10	115,255	26.55
Forfeited or expired	(26,686)	27.15			(48,410)	24.65	(57,616)	17.94
Exercised	(128,709)	12.34			(178,174)	13.14	(137,413)	9.07
Outstanding at end of year	1,381,782	16.03	5.6	$ 23,965	1,337,118	14.44	1,440,812	13.20
Exercisable at end of year	1,103,018	13.25	4.8	22,189	1,076,815	11.90	1,089,677	11.04

The weighted average fair value per share of options granted during 2007, 2006, and 2005 was $11.16, $14.96, and $12.99, respectively. The total intrinsic value of options exercised during 2007, 2006, and 2005 was $2.3 million,

$2.4 million, and $2.6 million, respectively. During 2007, 2006, and 2005, EAC received proceeds from the exercise of stock options of $1.6 million, $2.3 million, and $1.5 million, respectively. During 2006 and 2005, EAC realized tax benefits related to stock options of $0.9 million and $0.9 million, respectively. At December 31, 2007, EAC had $1.1 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.

ENCORE ACQUISITION COMPANY

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Additional information about options outstanding and exercisable at December 31, 2007 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	438,782	3.5	$ 8.88	438,782
2002	$8.50 to $12.40	284,435	4.8	11.94	284,435
2003	$11.49 to $13.61	36,594	5.6	12.31	36,594
2004	$17.17 to $19.77	264,054	6.1	17.54	264,054
2005	$26.55	72,594	7.1	26.55	48,183
2006	$31.10	93,207	8.1	31.10	30,970
2007	$25.73	192,116	9.1	25.73	
		1,381,782			1,103,018

Subsequent to December 31, 2007, EAC issued 176,170 stock options to employees as part of its annual incentive program.

Restricted Stock. During 2007, 2006, and 2005, EAC recognized expense related to restricted stock of $7.6 million, $7.3 million, and $4.0 million, respectively. During 2006 and 2005, EAC realized tax benefits related to restricted stock of $0.4 million and $0.5 million, respectively. The following table summarizes the changes in the number of unvested restricted stock awards and their related weighted average grant date fair value for 2007:

	Number of Shares	Weighted Average Grant Date Fair Value
Outstanding at January 1, 2007	828,619	$ 26.17
Granted	344,633	25.95
Vested	(184,867)	21.35
Forfeited	(70,047)	26.07
Outstanding at December 31, 2007	918,338	27.07

During 2007, 2006, and 2005, EAC issued 169,453 shares, 277,162 shares, and 130,854 shares, respectively, of restricted stock to employees and members of the Board which depend on the passage of time and continued employment for vesting. The following table illustrates by year of grant the vesting of outstanding restricted stock at

December 31, 2007 that depends only on the passage of time and continued employment for vesting:

	Year of Vesting					
Year of Grant	**2008**	**2009**	**2010**	**2011**	**2012**	**Total**
2003	17,195					17,195
2004	25,119	25,119				50,238
2005	76,016	71,512	71,512			219,040
2006	63,604	172,591	63,604			299,799
2007	34,290	34,334	41,834	41,832	7,500	159,790
Total	216,224	303,556	176,950	41,832	7,500	746,062

ENCORE ACQUISITION COMPANY

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

During 2007, 2006, and 2005, EAC issued 175,180 shares, 151,447 shares, and 155,190 shares of restricted stock to employees that not only depend on the passage of time and continued employment, but also on certain performance measures, for vesting. The performance measures related to the 2006 and 2005 awards were met and therefore, vesting depends only on the passage of time and continued employment. The following table illustrates by year of grant the vesting of outstanding restricted stock at December 31, 2007 that not only depends on the passage of time and continued employment, but also on certain performance measures, assuming the performance measures are met, for vesting:

	Year of Vesting				
Year of Grant	**2008**	**2009**	**2010**	**2011**	**Total**
2007	43,069	43,069	43,069	43,069	172,276

Subsequent to December 31, 2007, the performance measures related to the 2007 awards were met and therefore, vesting now depends only on the passage of time and continued employment.

As of December 31, 2007, EAC had $8.6 million of total unrecognized compensation cost related to unvested, outstanding restricted stock, which is expected to be recognized over a weighted average period of 2.6 years. None of EAC s unvested, outstanding restricted stock is subject to variable accounting. During 2007, 2006, and 2005, there were 184,867 shares, 101,377 shares, and 81,883 shares, respectively, of restricted stock that vested and employees elected to satisfy minimum tax withholding obligations related thereto by allowing EAC to withhold 38,978 shares, 24,362 shares, and 18,298 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 2007, 2006, and 2005 was $5.3 million, $2.6 million, and $2.6 million, respectively.

Subsequent to December 31, 2007, EAC issued 266,042 shares of restricted stock to employees as part of its annual incentive program.

Note 13. Financial Instruments

The following table sets forth the book value and estimated fair value of financial instrument assets (liabilities) as of the dates indicated:

	December 31,			
	2007		2006	
	Book Value	Fair Value	Book Value	Fair Value
	(In thousands)			
Cash and cash equivalents	$ 1,704	$ 1,704	$ 763	$ 763
Accounts receivable, net	134,880	134,880	81,470	81,470

Plugging bond	777	921	732	838
Bell Creek escrow	6,701	6,728	4,887	4,902
Accounts payable	(21,548)	(21,548)	(18,204)	(18,204)
6.25 Notes	(150,000)	(138,375)	(150,000)	(140,625)
6.0% Notes	(295,560)	(264,750)	(295,108)	(275,250)
7.25% Notes	(148,676)	(143,813)	(148,588)	(145,500)
Revolving credit facilities	(526,000)	(526,000)	(68,000)	(68,000)
Commodity derivative contracts	9,798	9,798	13,599	13,599
Deferred premiums on commodity derivative contracts	(51,926)	(51,926)	(54,671)	(54,671)

106

Table of Contents

ENCORE ACQUISITION COMPANY

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

The carrying amounts of cash and cash equivalents, accounts receivable, net, and accounts payable approximate fair value due to the short maturity of these instruments. The fair values of the Notes were determined using open market quotes as of December 31, 2007 and 2006. The difference between book value and fair value represents the premium or discount on that date. The book value of the revolving credit facilities approximates the fair value as the interest rate is variable. The plugging bond and Bell Creek escrow are included in Other assets on the accompanying Consolidated Balance Sheets and are classified as held to maturity and therefore, are recorded at amortized cost, which at December 31, 2007 and 2006 was less than fair value. Commodity derivative contracts are marked-to-market each quarter in accordance with the provisions of SFAS 133.

Derivative Financial Instruments

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. Additionally, EAC occasionally short sells put contracts with a strike price well below the floor price of a floor or collar in order to offset some of the cost of the contracts. Combined, the short floor and long floor are called a floor spread.

EAC had $51.9 million of deferred premiums payable at December 31, 2007, of which $26.2 million is considered long-term and is included in Derivatives in the non-current liabilities section of the accompanying Consolidated Balance Sheet and $25.7 million is considered current and is 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 2008 to January 2010. EAC recorded these premiums at their net present value at the time the contract was entered into and accretes that value up to the eventual settlement price by recording interest expense each period.

Commodity Derivative Contracts Mark-to-Market Accounting. As previously discussed, during July 2006, EAC elected to discontinue hedge accounting prospectively for all remaining commodity derivative contracts which were previously accounted for as hedges. While this change has no effect on cash flows, results of operations are affected by mark-to-market gains and losses, which fluctuate with the changes in oil and natural gas prices. Prior to the discontinuation of hedge accounting in July 2006, EAC designated certain of its commodity derivative contracts as hedges, whereby the effective portion of changes in the fair value of the contract was deferred, until the hedged production occurred, in AOCL included in stockholders equity in the accompanying Consolidated Balance Sheets rather than recognized currently in earnings.

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

Table of Contents

ENCORE ACQUISITION COMPANY

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

purchased floor component of these floor spreads has been included with EAC s other floor contracts and the short floor component is shown separately as negative volumes.

The following tables summarize EAC s open commodity derivative contracts as of December 31, 2007:

Oil Derivative Contracts

Period	Daily Floor Volume (Bbl)	Average Floor Price (per Bbl)	Daily Short Floor Volume (Bbl)	Average Short Floor Price (per Bbl)	Daily Cap Volume (Bbl)	Average Cap Price (per Bbl)	Daily Swap Volume (Bbl)	Average Swap Price (per Bbl)	Asset (Liability) Fair Market Value (in thousands)
Jan. 2008	4,000	$ 80.00		$	2,000	$ 100.75		$	$ (1,313)
	6,000	71.67			2,000	96.65			
	11,500	61.96	(2,000)	65.00					
	3,000	56.67	(4,000)	50.00			1,000	58.59	
Feb. June 2008	4,880	80.00			2,440	101.99			(6,714)
	6,000	71.67			2,000	96.65			
	11,500	61.96	(2,000)	65.00					
	3,000	56.67	(4,000)	50.00			1,000	58.59	
Second Half 2008	4,880	80.00			2,440	101.99	3,000	90.26	(341)
	6,000	71.67			2,000	96.65			
	7,500	63.00	(2,000)	65.00					
	3,000	56.67	(4,000)	50.00					
2009	880	80.00			440	97.75			9,222
	12,250	72.96	(1,250)	65.00					
	3,750	64.47	(5,000)	50.00			1,000	68.70	
2010	880	80.00			440	93.80			52
	2,000	75.00			1,000	77.23			
	2,000	65.00	(2,000)	65.00					
2011	1,000	80.00			1,000	94.65			1,811
	1,000	70.00							
									$ 2,717

Table of Contents

ENCORE ACQUISITION COMPANY

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Natural Gas Derivative Contracts

Period	Daily Floor Volume (Mcf)	Average Floor Price (per Mcf)	Daily Short Floor Volume (Mcf)	Average Short Floor Price (per Mcf)	Daily Cap Volume (Mcf)	Average Cap Price (per Mcf)	Daily Swap Volume (Mcf)	Average Swap Price (per Mcf)	Asset Fair Market Value (In thousands)
Jan. 2008	2,000	$ 8.20		$	2,000	$ 9.85		$	$ 159
	2,000	7.20							
	20,000	6.35							
Feb. - Dec. 2008	3,800	8.20			3,800	9.83			4,306
	3,800	7.20							
	20,000	6.35							
2009	3,800	8.20			3,800	9.83			1,376
	3,800	7.20							
2010	3,800	8.20			3,800	9.58			1,240
	3,800	7.20							
									$ 7,081

Commodity Derivative Contracts 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 $53.6 million, $60.3 million, and $59.3 million in 2007, 2006, and 2005, respectively. EAC also recognized derivative fair value gains and losses related to (i) changes in the market value since the date of dedesignation of commodity derivative contracts which were previously designated as hedges, (ii) changes in the market value of certain other derivative contracts that were never designated as hedges, (iii) settlements on derivative contracts not designated as hedges, and (iv) ineffectiveness of commodity derivative contracts designated as hedges prior to July 2006. The following table summarizes the components of derivative fair value loss (gain) for the periods indicated:

	Year Ended December 31, 2007	2006	2005
		(In thousands)	
Ineffectiveness on designated commodity derivative contracts	$	$ 1,748	$ 8,371
Mark-to-market loss (gain):			
Interest rate swap			462
Commodity derivative contracts	85,372	(31,205)	(10,539)
Premium amortization	41,051	13,926	8,489
Settlements:			

Interest rate swap			(312)
Commodity derivative contracts	(13,940)	(8,857)	(1,181)
Total derivative fair value loss (gain)	$ 112,483	$ (24,388)	$ 5,290

Commodity Derivative Contracts Future Period Impact. At December 31, 2007 and 2006, AOCL consisted entirely of deferred losses, net of tax, on commodity derivative contracts which were previously designated as hedges of $1.8 million and $35.3 million, respectively.

EAC expects to reclassify the remaining $2.9 million of deferred losses associated with its dedesignated commodity derivative contracts from AOCL to oil and natural gas revenues by June 30, 2008. EAC also expects to reclassify the remaining $1.1 million of net deferred income tax assets associated with its dedesignated commodity derivative contracts from AOCL to income tax benefit by June 30, 2008.

ENCORE ACQUISITION COMPANY

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Counterparty Risk. At December 31, 2007, EAC had committed greater than 10 percent of either its outstanding oil or natural gas commodity derivative contracts to the following counterparties:

Counterparty	Percentage of Oil Derivative Contracts Committed	Percentage of Natural Gas Derivative Contracts Committed
Bank of America, N.A.	18%	
BNP Paribas	25%	40%
Calyon	10%	28%
Deutsche Bank	20%	
Wachovia	10%	32%

EAC believes that its credit-worthiness as well as that of its current counterparties is sound and EAC does not anticipate any non-performance of contractual obligations. As long as each counterparty maintains an investment grade credit rating, no collateral is required.

In order to mitigate the credit risk of financial instruments, EAC enters into master netting agreements with significant counterparties. The master netting agreement is a standardized, bilateral contract between a given counterparty and EAC. Instead of treating separately each financial transaction between the counterparty and EAC, the master netting agreement enables the counterparty and EAC to aggregate all financial trades and treat them as a single agreement. This arrangement benefits EAC in three ways: (i) the netting of the value of all trades reduces the requirements of daily collateral posting by EAC, (ii) default by a counterparty under one financial trade can trigger rights to terminate all financial trades with such counterparty, and (iii) netting of settlement amounts reduces EAC s credit exposure to a given counterparty in the event of close-out.

Note 14. Related Party Transactions

EAC paid $1.6 million, $3.3 million, and $1.0 million to affiliates of Exterran Holdings, Inc., the successor of Hanover Compressor Company (Hanover), in 2007, 2006, and 2005, respectively, for compressors and field compression services. Mr. I. Jon Brumley, EAC s Chairman of the Board, served as a director of Hanover until August 2007.

EAC received $90.3 million, $7.4 million, and $1.4 million from affiliates of Tesoro Corporation (Tesoro) in 2007, 2006, and 2005, respectively, related to gross production sold from wells operated by Encore Operating. Mr. John V. Genova, a member of the Board, is employed by Tesoro.

Note 15. Financial Statements of Subsidiary Guarantors

In February 2007, EAC formed certain non-guarantor subsidiaries in connection with the formation of ENP. See Note 16. ENP for additional discussion of ENP s formation and other matters. As of December 31, 2007, certain of

EAC s wholly owned subsidiaries were subsidiary guarantors of the Notes. The subsidiary guarantees are full and unconditional, and joint and several. The subsidiary guarantors may, without restriction, transfer funds to EAC in the form of cash dividends, loans, and advances. In accordance with SEC rules, EAC has prepared condensed consolidating financial statements in order to quantify the financial position, results of operations, and cash flows of the subsidiary guarantors. The following Condensed Consolidating Balance Sheet as of December 31, 2007 and Condensed Consolidating Statement of Operations and Comprehensive Income (Loss) and Condensed Consolidating Statement of Cash Flows for the year then ended present consolidating financial information for Encore Acquisition Company (Parent) on a stand alone, unconsolidated basis, and

ENCORE ACQUISITION COMPANY

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

its combined guarantor and combined non-guarantor subsidiaries. As of December 31, 2007, EAC s guarantor subsidiaries were:

EAP Properties, Inc.;

EAP Operating, LLC;

Encore Operating; and

Encore Operating Louisiana, LLC.

As of December 31, 2007, EAC s non-guarantor subsidiaries were:

ENP;

OLLC;

Encore Partners GP Holdings LLC;

Encore Partners LP Holdings LLC;

GP LLC; and

Encore Clear Fork Pipeline LLC.

All intercompany investments in, loans due to/from, subsidiary equity, and revenues and expenses between the Parent, guarantor subsidiaries, and non-guarantor subsidiaries are shown prior to consolidation with the Parent and then eliminated to arrive at consolidated totals per the accompanying consolidated financial statements of EAC. Prior to February 2007, all of EAC s subsidiaries were subsidiary guarantors of the Notes. Therefore, comparative condensed consolidating financial statements are not presented as of December 31, 2006 or for the years ended December 31, 2006 and 2005.

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

Table of Contents

ENCORE ACQUISITION COMPANY

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

CONDENSED CONSOLIDATING BALANCE SHEET

December 31, 2007

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

Commitments and contingencies (see Note 4)					
Minority interest in consolidated partnership			122,534		122,534
Total stockholders equity	948,155	1,935,480	175,629	(2,111,109)	948,155
Total liabilities and stockholders equity	$ 2,640,592	$ 2,672,292	$ 390,079	$ (2,918,402)	$ 2,784,561

ENCORE ACQUISITION COMPANY

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

	Parent	Guarantor Subsidiaries	Non-Guarantor Subsidiaries (In thousands)	Eliminations	Consolidated Total
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 operations		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 income (expenses)	46,961	1,320	(12,098)	(122,220)	(86,037)
Income (loss) before income taxes and minority interest	31,633	138,039	(25,343)	(120,176)	24,153

Income tax provision	(14,478)		2		(14,476)
Minority interest in loss of consolidated partnership			7,478		7,478
Net income (loss)	17,155	138,039	(17,863)	(120,176)	17,155
Amortization of deferred hedge losses (gains), net of tax	(20,047)	53,588			33,541
Comprehensive income (loss)	$ (2,892)	$ 191,627	$ (17,863)	$ (120,176)	$ 50,696

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 provided by (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
Exercise of stock options and vesting of restricted stock, net of treasury stock purchases	454				454
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		(22,387)	(5,569)		(27,956)
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
Cash and cash equivalents, beginning of period		763			763
Cash and cash equivalents, end of period	$ 1	$ 1,700	$ 3	$	$ 1,704

Note 16. ENP

In September 2007, ENP completed its IPO of 9,000,000 common units, representing a 37.4 percent limited partner interest, at a price to the public of $21.00 per unit. In October 2007, the underwriters exercised their over-allotment option to purchase an additional 1,148,400 common units of ENP, representing an additional 2.9 percent limited partner interest. 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 the $126.4 million of outstanding indebtedness under ENP s subordinated credit agreement with EAP Operating Inc., and reduce outstanding borrowings under the OLLC Credit Agreement.

ENCORE ACQUISITION COMPANY

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

In connection with the closing of the IPO, EAC, ENP, and certain of their respective subsidiaries entered into a contribution, conveyance and assumption agreement (the Contribution Agreement) and an amended and restated administrative services agreement (the Administrative Services Agreement), each as more fully described below. In addition, prior to the IPO, GP LLC approved a long-term incentive plan (the ENP Plan), as more fully described below.

Contribution, Conveyance and Assumption Agreement

ENP entered into the Contribution Agreement with GP LLC, OLLC, EAC, Encore Operating, and Encore Partners LP Holdings LLC. At the closing of the IPO, the following transactions, among others, occurred pursuant to the Contribution Agreement:

Encore Operating transferred certain assets in the Permian Basin 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, the 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 two percent general partner interest in ENP. GP LLC received the common units through capital contributions from EAC and its subsidiaries of common units they owned.

Administrative Services Agreement

ENP entered into the Administrative Services Agreement with GP LLC, OLLC, Encore Operating, and EAC, whereby Encore Operating performs administrative services for ENP, such as accounting, corporate development, finance, land, legal, and engineering. In addition, Encore Operating provides all personnel and any facilities, goods, and equipment necessary to perform these services and not otherwise provided by the Partnership. Encore Operating receives an administrative fee of $1.75 per BOE of ENP s production for such services and reimbursement of actual third-party expenses incurred on ENP s behalf.

In addition, Encore Operating is entitled to retain any COPAS overhead charges associated with drilling and operating wells that would otherwise be paid by non-operating interest owners to the operator of a well. Most joint operating agreements provide for an annual increase or decrease in the COPAS overhead rate for drilling and producing wells. The rate change, which occurs annually in April, is based on the change in average weekly earnings as measured by an index published by the United States Department of Labor, Bureau of Labor Statistics. The COPAS overhead cost is charged to all non-operating interest owners under a joint operating agreement each month.

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

ENP does not have any employees. The employees supporting the operation of ENP are employees of EAC or its subsidiaries. Accordingly, EAC recognizes all employee-related expenses and liabilities in its consolidated financial statements. Encore Operating has substantial discretion in determining which third-party expenses to incur on ENP s behalf. ENP also pays its share of expenses that are directly chargeable to wells under joint operating agreements. Encore Operating is not liable to ENP for its performance of, or failure to

ENCORE ACQUISITION COMPANY

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

perform, services under the Administrative Services Agreement unless its acts or omissions constitute gross negligence or willful misconduct.

Long-Term Incentive Plan

The ENP Plan 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 Encore Operating, GP LLC, and any of their subsidiaries and affiliates who perform services for ENP are eligible to be granted awards under the ENP Plan. The total number of shares of common units reserved for issuance pursuant to the ENP Plan is 1,150,000. As of December 31, 2007, there were 1,130,000 units available for issuance under the ENP Plan. The ENP Plan is administered by the board of directors of GP LLC or a committee thereof, referred to as the plan administrator.

On October 29, 2007, ENP issued 20,000 phantom units to members 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. These phantom units are classified as liability awards under SFAS 123R. Accordingly, ENP determines the fair value of these awards at each reporting period, based on the closing unit price of ENP, and recognizes the liability as a component of Other noncurrent liabilities in the accompanying Consolidated Balance Sheets. For liability awards, the fair value of the award, which determines the measurement of the liability on the balance sheet, is remeasured at each reporting period until the award is settled. Changes in the fair value of the liability award from period to period are recorded as increases or decreases in compensation expense, over the remaining service period. The phantom units vest in four equal installments on October 29, 2008, 2009, 2010, and 2011. The holders of phantom units are also entitled to receive distribution equivalent rights prior to vesting, which entitle the grantee to receive cash equal to the amount of any cash distributions made by ENP with respect to a common unit during the period the right is outstanding.

During 2007, ENP recognized total compensation expense of approximately $31,000 for the phantom units, which is included in General and administrative expense in the accompanying Consolidated Statements of Operations.

Subsequent to December 31, 2007, ENP issued 5,000 phantom units to a new member of GP LLC s board of directors pursuant to the ENP Plan.

Management Incentive Units (MIUs)

In May 2007, the board of directors of GP LLC issued 550,000 MIUs to the executive officers of GP LLC. MIUs are a limited partner interest in ENP that entitles the holder to an initial quarterly distribution of $0.35 per MIU (or $1.40 on an annualized basis) to the extent paid to ENP s common unitholders and to increasing distributions upon the achievement of 10 percent compounding increases in ENP s distribution rate to common unitholders. MIUs are also convertible into common units upon the occurrence of certain events. MIUs are subject to a maximum limit on the aggregate number of common units issuable to, and the aggregate distributions payable to, holders of MIUs as follows:

- the holders of MIUs are not entitled to receive, in the aggregate, common units upon conversion of the MIUs that exceed a maximum limit of 5.1 percent of ENP s then-outstanding common units; and the holders of MIUs are not entitled to receive, in the aggregate, distributions of ENP s available cash in an amount that exceeds a maximum limit of 5.1 percent of all such distributions to all unitholders at the time of any such distribution.

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

Table of Contents

ENCORE ACQUISITION COMPANY

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

MIUs vest in three equal installments. The first installment vested upon the closing of the IPO, and subsequent vestings will occur on the first and second anniversary of such closing date. During 2007, ENP recognized total compensation expense for MIUs of $6.8 million, which is included in General and administrative expense in the accompanying Consolidated Statements of Operations. As of December 31, 2007, ENP had $4.8 million of total unrecognized compensation cost related to unvested, outstanding MIUs, which is expected to be recognized over a weighted average period of 0.7 years. For the first three quarters of 2008, the expense will be approximately $1.1 million per quarter, and for the fourth quarter of 2008 through the third quarter of 2009, the expense will be approximately $0.4 million per quarter. There have been no additional issuances or forfeitures of MIUs.

Distributions

On October 29, 2007, ENP declared a cash distribution for the third quarter of 2007 to unitholders of record as of the close of business on November 8, 2007. Approximately $0.5 million was paid on November 14, 2007 to minority interest unitholders at a rate of $0.053 per unit. The quarterly distribution of $0.053 per unit was based on an initial quarterly distribution of $0.35 per unit, prorated for the period from and including September 17, 2007 (the closing date of the IPO) through September 30, 2007.

Note 17. Segment Information

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

Table of Contents

ENCORE ACQUISITION COMPANY

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

The following table provides EAC s operating segment information required by 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 SFAS No. 69, *Disclosures about Oil and Gas Producing Activities* .

	For the Year Ended December 31, 2007			
	EAC Standalone	ENP	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 operations	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	30,461	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	16,304	762		17,066
Total expenses	553,867	92,932	(2,044)	644,755
Operating income (loss)	121,391	(13,245)	2,044	110,190
Other income (expenses):				
Interest	(82,825)	(12,294)	6,415	(88,704)
Other	10,930	196	(8,459)	2,667
Total other income (expenses)	(71,895)	(12,098)	(2,044)	(86,037)
Income (loss) before income taxes and minority interest	49,496	(25,343)		24,153
Income tax provision	(14,478)	2		(14,476)
Minority interest in loss of consolidated partnership	7,478			7,478

Net income (loss)		42,496		(25,341)				17,155
Amortization of deferred hedge losses (gains) , net of tax		33,541						33,541
Comprehensive income (loss)	$	76,037	$	(25,341)	$		$	50,696
Costs incurred related to oil and natural gas properties	$	874,811	$	341,348	$		$	1,216,159
Segment assets (as of December 31, 2007)	$	2,395,135	$	390,079	$	(653)	$	2,784,561

Table of Contents

ENCORE ACQUISITION COMPANY

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Note 18. Subsequent Events Unaudited

Commodity Derivative Contracts

Subsequent to December 31, 2007, EAC entered into additional commodity derivative contracts. The following tables summarize EAC s open commodity derivative contracts as of February 20, 2008:

Oil Derivative Contracts

Period	Daily Floor Volume (Bbl)	Average Floor Price (Per Bbl)	Daily Short Floor Volume (Bbl)	Average Short Floor Price (Per Bbl)	Daily Cap Volume (Bbl)	Average Cap Price (Per Bbl)	Daily Swap Volume (Bbl)	Average Swap Price (Per Bbl)
First Half 2008	19,880	$ 83.77		$	2,440	$ 101.99		$
	6,000	71.67			2,000	96.65		
	11,500	61.96	(2,000)	65.00				
	3,000	56.67	(4,000)	50.00			1,000	58.59
Second Half 2008	14,880	83.36			2,440	101.99	5,000	91.56
	6,000	71.67			2,000	96.65		
	7,500	63.00	(2,000)	65.00				
	3,000	56.67	(4,000)	50.00				
2009	13,380	80.00	(10,000)	72.50	440	97.75	2,000	90.46
	12,250	72.96	(3,750)	65.00			3,000	89.22
	3,750	64.47	(5,000)	50.00			1,000	68.70
2010	880	80.00			440	93.80		
	2,000	75.00			1,000	77.23		
	2,000	65.00	(2,000)	65.00				
2011	1,880	80.00			1,440	95.41		
	1,000	70.00						

Natural Gas Derivative Contracts

Period	Daily Floor Volume (Mcf)	Average Floor Price (Per Mcf)	Daily Short Floor Volume (Mcf)	Average Short Floor Price (Per Mcf)	Daily Cap Volume (Mcf)	Average Cap Price (Per Mcf)	Daily Swap Volume (Mcf)	Average Swap Price (Per Mcf)

2008	6,300	$	8.18	$	6,300	$	9.52	5,000	$	8.14
	11,300		7.38		7,500		8.35	5,000		7.47
	20,000		6.35							
2009	3,800		8.20		3,800		9.83			
	3,800		7.20							
2010	3,800		8.20		3,800		9.58			
	3,800		7.20							

As of February 20, 2008, EAC s total hedge premiums were $62.4 million, $46.2 million, $7.3 million, and $4.4 million for 2008, 2009, 2010, and 2011, respectively.

Purchase and Investment Agreement

On December 27, 2007, OLLC entered into a purchase and investment agreement with Encore Operating, whereby OLLC acquired certain oil and natural gas producing properties and related assets in the Permian and

ENCORE ACQUISITION COMPANY

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Williston Basins from Encore Operating. The transaction closed on February 7, 2008, but was effective as of January 1, 2008.

The consideration for the acquisition consisted of approximately $125.4 million in cash and 6,884,776 common units representing limited partner interests in ENP. The cash portion of the purchase price was funded through borrowings under the OLLC Credit Agreement. Upon completion of the acquisition, the borrowing base under the OLLC Credit Agreement was increased to $240 million.

The acquisition will be accounted for as a transaction between entities under common control. Therefore, the assets will be recorded on ENP s balance sheet at EAC s historical basis, and the historical results of operations of ENP will be restated to reflect the historical operating results of the combined operations.

Subsequent to December 31, 2007, as a result of the increase in debt levels resulting from the acquisition, ENP entered into interest rate swaps whereby it swapped $100 million of floating rate debt to a fixed rate with a LIBOR rate of 3.06 percent and an expected margin of 1.25 percent on the OLLC Credit Agreement.

Other Events

On January 21, 2008, ENP declared a cash distribution for the fourth quarter of 2007 to unitholders of record as of the close of business on February 6, 2008. Approximately $3.9 million was paid on February 14, 2008 to minority interest unitholders at a rate of $0.3875 per unit.

Subsequent to December 31, 2007 through February 25, 2008, EAC repurchased 844,191 shares of its outstanding common stock for approximately $27.2 million, or an average of $32.23 per share, under its share repurchase program.

Effective February 7, 2008, EAC amended the EAC Credit Agreement to, among other things, provide that certain negative covenants in the EAC Credit Agreement restricting hedge transactions do not apply to any oil and natural gas hedge transaction that is a floor or put transaction not requiring any future payments or delivery by EAC or any of its restricted subsidiaries.

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, 2007	December 31, 2006
	(In thousands)	
Properties and equipment, at cost successful efforts method:		
Proved properties, including wells and related equipment	$ 2,845,776	$ 2,033,914
Unproved properties	63,352	47,548
Accumulated depletion, depreciation, and amortization	(489,004)	(364,780)
	$ 2,420,124	$ 1,716,682

The following table summarizes costs incurred related to oil and natural gas properties for the periods indicated:

	Year Ended December 31, 2007	2006	2005
	(In thousands)		
Acquisitions:			
Proved properties	$ 787,988	$ 4,486	$ 224,469
Unproved properties	52,306	24,462	21,205
Asset retirement obligations	8,251	785	2,221
Total acquisitions	848,545	29,733	247,895
Development:			
Drilling and exploitation	270,016	253,484	268,520
Asset retirement obligations	145	147	954
Total development	270,161	253,631	269,474
Exploration:			
Drilling and exploitation	95,221	92,839	53,316
Geological and seismic	1,456	1,720	3,095
Delay rentals	776	646	635
Total exploration	97,453	95,205	57,046
Total costs incurred	$ 1,216,159	$ 378,569	$ 574,415

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 and the FASB. 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 production may not equal the estimated amounts used in the preparation of reserve projections. In accordance with SEC guidelines, 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

ENCORE ACQUISITION COMPANY

SUPPLEMENTARY INFORMATION (Continued)

constant throughout the life of the properties. Year-end prices used in estimating net cash flows were as follows as of the dates indicated:

	December 31,		
	2007	2006	2005
Oil (per Bbl)	$ 96.01	$ 61.06	$ 61.04
Natural gas (per Mcf)	$ 7.47	$ 5.48	$ 9.44

EAC s 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 costs 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 net operating loss, and alternative minimum tax.

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,		
	2007	2006	2005
Proved reserves:			
Oil (MBbl)	188,587	153,434	148,387
Natural gas (MMcf)	256,447	306,764	283,865
Combined (MBOE)	231,328	204,561	195,698
Proved developed reserves:			
Oil (MBbl)	125,213	94,246	101,505
Natural gas (MMcf)	191,072	235,049	229,950
Combined (MBOE)	157,058	133,421	139,830

EAC is committed to sell at least 4,500 Bbls/D at a floating market price through 2009.

ENCORE ACQUISITION COMPANY

SUPPLEMENTARY INFORMATION (Continued)

The changes in proved reserves were as follows for the periods indicated:

	Oil (MBbl)	Natural Gas (MMcf)	Oil Equivalent (MBOE)
Balance, December 31, 2004	134,048	234,030	173,053
Purchases of minerals-in-place	8,333	38,781	14,796
Extensions and discoveries	2,780	28,073	7,459
Improved recovery	11,510	1,132	11,699
Revisions of previous estimates	(1,413)	2,908	(928)
Production	(6,871)	(21,059)	(10,381)
Balance, December 31, 2005	148,387	283,865	195,698
Purchases of minerals-in-place	25	235	64
Extensions and discoveries	3,269	78,861	16,412
Improved recovery	10,935	941	11,092
Revisions of previous estimates	(1,847)	(33,682)	(7,461)
Production	(7,335)	(23,456)	(11,244)
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(a)	188,587	256,447	231,328

(a) Includes reserves of 20,940 MBOE comprised of 14,417 MBbls of oil and 39,141 MMcf of natural gas attributable to ENP in which there is a 40.2 percent minority interest as of December 31, 2007.

The Standardized Measure of discounted estimated future net cash flows was as follows as of the dates indicated:

	December 31, 2007	2006	2005
	(In thousands)		
Future cash inflows	$ 17,394,468	$ 9,291,007	$ 10,414,091

Future production costs	(5,721,804)	(3,668,897)	(3,690,974)
Future development costs	(469,034)	(371,396)	(250,554)
Future abandonment costs, net of salvage	(75,172)	(134,103)	(121,553)
Future income tax expense	(3,236,356)	(1,499,290)	(1,934,504)
Future net cash flows	7,892,102	3,617,321	4,416,506
10% annual discount	(4,600,393)	(2,155,514)	(2,498,035)
Standardized measure of discounted estimated future net cash flows(a)	$ 3,291,709	$ 1,461,807	$ 1,918,471

ENCORE ACQUISITION COMPANY

SUPPLEMENTARY INFORMATION (Continued)

(a) Includes $438.4 million attributable to ENP in which there is a 40.2 percent minority interest as of December 31, 2007.

The primary changes in the Standardized Measure of discounted estimated future net cash flows were as follows for the periods indicated:

	Year Ended December 31,		
	2007	2006	2005
		(In thousands)	
Net change in prices and production costs	$ 1,718,818	$ (634,033)	$ 531,793
Purchases of minerals-in-place	1,249,008	539	256,257
Sales of minerals-in-place	(300,727)		
Extensions, discoveries, and improved recovery	282,163	141,211	229,929
Revisions of previous quantity estimates	21,887	(62,615)	(15,455)
Production, net of production costs	(710,134)	(340,036)	(357,028)
Development costs incurred during the period	270,016	253,484	268,520
Accretion of discount	146,181	191,847	116,562
Change in estimated future development costs	(235,005)	(185,212)	(199,158)
Net change in income taxes	(672,807)	248,491	(247,937)
Change in timing and other	60,502	(70,340)	169,369
Net change in standardized measure	1,829,902	(456,664)	752,852
Standardized measure, beginning of year	1,461,807	1,918,471	1,165,619
Standardized measure, end of year	$ 3,291,709	$ 1,461,807	$ 1,918,471

ENCORE ACQUISITION COMPANY

SUPPLEMENTARY INFORMATION (Continued)

Selected Quarterly Financial Data Unaudited

The following table provides selected quarterly financial data for 2007 and 2006:

	Quarter			
	First	Second	Third	Fourth
	(In thousands, except per share data)			
2007				
Revenues	$ 130,542	$ 189,643	$ 195,016	$ 239,744
Operating income (loss)	$ (29,592)	$ 50,914	$ 41,059	$ 47,809
Net income (loss)	$ (29,429)	$ 15,171	$ 11,985	$ 19,428
Net income (loss) per share:				
Basic	$ (0.55)	$ 0.29	$ 0.23	$ 0.36
Diluted	$ (0.55)	$ 0.28	$ 0.22	$ 0.36
2006				
Revenues, as reported	$ 116,216	$ 133,471	$ 177,697	$ 157,710
Plus: change in marketing presentation	31,746	24,022		
Revenues, as restated	$ 147,962	$ 157,493	$ 177,697	$ 157,710
Operating income	$ 40,846	$ 47,594	$ 78,002	$ 25,064
Net income	$ 17,936	$ 22,235	$ 42,135	$ 10,092
Net income per share:				
Basic	$ 0.37	$ 0.42	$ 0.80	$ 0.19
Diluted	$ 0.36	$ 0.42	$ 0.78	$ 0.19

During the third quarter of 2006, EAC reclassified the net gain/loss from the purchases and sales of third party oil volumes from Oil revenues to Marketing revenues and Marketing expense and reclassified the related marketing transportation costs from Other operating expense to Marketing expense in EAC s Consolidated Statements of Operations for the first and second quarters of 2006. These are changes in presentation only and do not affect previously reported net income or earnings per share for either period.

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

As of the end of the period covered by this Report, we carried out an evaluation, under the supervision and with the participation of our management, including our Chief Executive Officer and Chief Financial Officer, of the effectiveness of the design and operation of our disclosure controls and procedures (as defined in Rule 13a-15(e) of the Exchange Act). 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, 2007 to ensure that information required to be disclosed in our reports filed or submitted under the Exchange Act is recorded, processed, summarized, and reported within the time periods specified in the SEC s rules and forms and that information required to be disclosed is accumulated and communicated to management, including our Chief Executive Officer and Chief Financial Officer, to allow timely decisions regarding required disclosure.

Management s Report on Internal Control Over Financial Reporting

EAC s management is responsible for establishing and maintaining adequate internal control over financial reporting. EAC s internal control over financial reporting is a process designed under the supervision of EAC s Chief Executive Officer and Chief Financial Officer to provide reasonable assurance regarding the reliability of financial reporting and the preparation of EAC s financial statements for external purposes in accordance with generally accepted accounting principles.

As of December 31, 2007, management assessed the effectiveness of EAC s 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 EAC maintained effective internal control over financial reporting as of December 31, 2007, based on those criteria.

Ernst & Young, LLP, the independent registered public accounting firm that audited the consolidated financial statements of EAC included in this annual report on Form 10-K, has issued an attestation report on the effectiveness of EAC s internal control over financial reporting as of December 31, 2007. The report, which expresses an unqualified opinion on the effectiveness of EAC s internal control over financial reporting as of December 31, 2007, is included below under the heading Report of Independent Registered Public Accounting Firm on Internal Control Over Financial Reporting .

Table of Contents

ENCORE ACQUISITION COMPANY

Report of Independent Registered Public Accounting Firm on Internal Control Over Financial Reporting

The Board of Directors and Stockholders of
Encore Acquisition Company:

We have audited Encore Acquisition Company s internal control over financial reporting as of December 31, 2007, 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, 2007, 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, 2007 and 2006, and the related consolidated statements of operations, stockholders equity, and cash flows for each of the three years in the period ended December 31, 2007, and our report dated February 27, 2008 expressed an unqualified opinion thereon.

/s/ Ernst & Young LLP

Fort Worth, Texas
February 27, 2008

Table of Contents

ENCORE ACQUISITION COMPANY

Changes in Internal Control over Financial Reporting

There were no changes in our internal control over financial reporting that occurred during the quarter ended December 31, 2007 that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

ITEM 9B. *OTHER INFORMATION*

On February 11, 2003, our board of directors adopted the 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 defined in the plan). If during such time period, a member of the strategic group is involuntarily terminated by us other than for cause or he resigns for good reason (as defined in the plan), the person will receive certain benefits, including cash equal to twice his annual salary and bonus. On February 18, 2008, the Compensation Committee authorized an increase in the multiple of annual salary and bonus payable under the plan to Mr. Jon S. Brumley, our Chief Executive Officer and President, from 2 times annual salary and bonus to 2.5 times annual salary and bonus.

Also on February 18, 2008, the Compensation Committee approved personal use of our aircraft for Mr. I. Jon Brumley, our Chairman of the Board, and Mr. Jon S. Brumley, our Chief Executive Officer and President. Both executives are allowed personal use of our 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 amount equal to 10 percent of jet fuel relating to personal use in excess of 15 hours per year.

PART III

ITEM 10. *DIRECTORS, EXECUTIVE OFFICERS AND CORPORATE GOVERNANCE*

The information required in response to this item will be set forth in our definitive proxy statement for the 2008 annual meeting of stockholders and is incorporated herein by reference.

We have adopted a Code of Business Conduct and Ethics covering our directors, officers, and employees, which is available free of charge on our website (www.encoreacq.com). 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.

ITEM 11. *EXECUTIVE COMPENSATION*

The information required in response to this item will be set forth in our definitive proxy statement for the 2008 annual meeting of stockholders and is incorporated herein by reference.

ENCORE ACQUISITION COMPANY

ITEM 12. *SECURITY OWNERSHIP OF CERTAIN BENEFICIAL OWNERS AND MANAGEMENT AND RELATED STOCKHOLDER MATTERS*

The information required in response to this item will be set forth in our definitive proxy statement for the 2008 annual meeting of stockholders and is incorporated herein by reference.

ITEM 13. *CERTAIN RELATIONSHIPS AND RELATED TRANSACTIONS, AND DIRECTOR INDEPENDENCE*

The information required in response to this item will be set forth in our definitive proxy statement for the 2008 annual meeting of stockholders and is incorporated herein by reference.

ITEM 14. *PRINCIPAL ACCOUNTING FEES AND SERVICES*

The information required in response to this item will be set forth in our definitive proxy statement for the 2008 annual meeting of stockholders and is incorporated herein by reference.

Table of Contents

ENCORE ACQUISITION COMPANY

PART IV

ITEM 15. ***EXHIBITS, 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

See Index to Exhibits on the following page for a description of the exhibits filed as a part of this Report.

ENCORE ACQUISITION COMPANY

INDEX TO EXHIBITS

Exhibit No.	Description
2.1	Purchase and Sale Agreement dated January 16, 2007 among Clear Fork Pipeline Company, Howell Petroleum Corporation, Kerr-McGee Oil & Gas Onshore LP, and EAC (incorporated by reference to Exhibit 2.1 of EAC s Current Report on Form 8-K, filed with the SEC on January 17, 2007).
2.2	Purchase and Sale Agreement dated January 23, 2007 among Howell Petroleum Corporation and Kerr-McGee Oil & Gas Onshore LP, as Sellers, and EAC, as Purchaser (incorporated by reference to Exhibit 2.1 of EAC s Current Report on Form 8-K, filed with the SEC on January 26, 2007).
2.3	Purchase and Sale Agreement dated May 16, 2007 between Crow Creek and Encore Operating, L.P. (incorporated by reference from EAC s Current Report on Form 8-K, filed with the SEC on July 6, 2007).
3.1	Second Amended and Restated Certificate of Incorporation of EAC (incorporated by reference to EAC s Quarterly Report on Form 10-Q for the fiscal quarter ended September 30, 2001, filed with the SEC on November 7, 2001).
3.1.2	Certificate of Amendment to Second Amended and Restated Certificate of Incorporation of EAC (incorporated by reference to EAC s Quarterly Report on Form 10-Q for the fiscal quarter ended March 31, 2005, filed with the SEC on May 5, 2005).
3.2	Second Amended and Restated Bylaws of EAC (incorporated by reference to EAC s Quarterly Report on Form 10-Q for the fiscal quarter ended September 30, 2001, filed with the SEC on November 7, 2001).
4.1	Specimen certificate of EAC (incorporated by referenced to Exhibit 4.1 to 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 EAC, 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 to 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 EAC, the subsidiary guarantors party thereto and Wells Fargo Bank, National Association, with respect to the 6.25% Senior Subordinated Notes due 2014.
4.3.1	Indenture, dated as of July 13, 2005, among EAC, 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 to 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 EAC, the subsidiary guarantors party thereto and Wells Fargo Bank, National Association, with respect to the 6.0% Senior Subordinated Notes due 2015.
4.4.1	Indenture, dated as of November 16, 2005, among EAC, the subsidiary guarantors party thereto and Wells Fargo Bank, National Association with respect to Subordinated Debt Securities (incorporated by reference to 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 EAC, 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 to 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).
4.4.4*	Second Supplemental Indenture, dated as of January 2, 2008, among EAC, the subsidiary guarantors party thereto and Wells Fargo Bank, National Association, with respect to the 7.25% Senior Subordinated Notes due 2017.
10.1+	2000 Incentive Stock Plan (incorporated by reference to Exhibit 4.1 to EAC s Registration Statement on Form S-8 (File No. 333-120422), filed with the SEC on November 12, 2004).

ENCORE ACQUISITION COMPANY

Exhibit No.	Description
10.2+	Employee Severance Protection Plan (incorporated by reference to Exhibit 10.1 to EAC s Quarterly Report on Form 10-Q for the quarterly period ended March 31, 2003, filed with the SEC on May 8, 2003).
10.3+	Form of Restricted Stock Award Executive (incorporated by reference to Exhibit 10.3 to EAC s Quarterly Report on Form 10-Q for the quarter ended March 31, 2007, filed with the SEC on May 10, 2007).
10.4+	Form of Stock Option Agreement Nonqualified (incorporated by reference to Exhibit 10.4 to EAC s Quarterly Report on Form 10-Q for the quarter ended March 31, 2007, filed with the SEC on May 10, 2007).
10.5+	Form of Stock Option Agreement Incentive (incorporated by reference to Exhibit 10.5 to EAC s Quarterly Report on Form 10-Q for the quarter ended March 31, 2007, filed with the SEC on March 1, 2007).
10.6+	Form of Indemnification Agreement for directors and executive officers (incorporated by reference to 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).
10.7	Description of Compensation Payable to Non-Management Directors (incorporated by reference to Exhibit 10.1 of EAC s Current Report on Form 8-K, filed with the SEC on February 22, 2006).
10.8	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).
10.9	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).
10.10	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 to Exhibit 10.2 to EAC s Current Report on Form 8-K, filed with the SEC on March 13, 2007).
10.11	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).
10.12	Contribution, Conveyance and Assumption Agreement, dated as of September 17, 2007, by and among Encore Energy Partners LP, Encore Energy Partners GP LLC, Encore Acquisition Company, Encore Operating, L.P., Encore Partners GP Holdings LLC, Encore Partners LP Holdings LLC and Encore Energy Partners Operating LLC (incorporated by reference from Exhibit 10.1 to EAC s Current Report on Form 8-K, filed with the SEC on September 21, 2007).

10.13	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).
10.14	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).
10.15	Second Amended and Restated Agreement of Limited Partnership of Encore Energy Partners LP (incorporated by reference to Exhibit 10.3 to EAC s Current Report on Form 8-K, filed with the SEC on September 21, 2007).
12.1*	Statement showing computation of ratios of earnings to fixed charges.
21.1*	Subsidiaries of EAC as of February 20, 2008.

Table of Contents

ENCORE ACQUISITION COMPANY

Exhibit No.	Description
23.1*	Consent of Ernst & Young LLP.
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).

* 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 26, 2008

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 26, 2008
/s/ Jon S. Brumley Jon S. Brumley	Chief Executive Officer, President, and Director (Principal Executive Officer)	February 26, 2008
/s/ Robert C. Reeves Robert C. Reeves	Senior Vice President, Chief Financial Officer, and Treasurer (Principal Financial Officer)	February 26, 2008
/s/ Andrea Hunter Andrea Hunter	Vice President, Controller and Principal Accounting Officer	February 26, 2008

/s/ John A. Bailey	Director	February 26, 2008
John A. Bailey		
/s/ Martin C. Bowen	Director	February 26, 2008
Martin C. Bowen		
/s/ Ted Collins, Jr.	Director	February 26, 2008
Ted Collins, Jr.		
/s/ Ted A. Gardner	Director	February 26, 2008
Ted A. Gardner		

Table of Contents

ENCORE ACQUISITION COMPANY

Signature	Title or Capacity	Date
/s/ John V. Genova	Director	February 26, 2008
John V. Genova		
/s/ James A. Winne III	Director	February 26, 2008
James A. Winne III		