ENCORE ACQUISITION CO
Form 10-K
February 28, 2008

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.

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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.

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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.

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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.

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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

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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.

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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.

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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

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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	

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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.

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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

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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

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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;

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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

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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

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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

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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

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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.

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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.

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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%
tal	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.

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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

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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.

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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.

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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.

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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

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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.

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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

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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

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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.

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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.

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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

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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

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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.

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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.

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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;

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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.

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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

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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

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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			

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	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.

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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 .

<u>Introduction</u>

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

<u>Overview of Business</u>

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

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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

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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.

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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.

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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)%*

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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	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.

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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	Year Ended December 31, 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)

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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

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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

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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	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	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*

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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%

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	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.

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	Year Ended December 31, 2006	Year Ended December 31, 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

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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

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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

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$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.

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

	Year Ended December 31, 2006	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.

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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

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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	Payments Due by Period (In thousands) Total	2008	2009-2010	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

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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

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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.

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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.

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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

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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