ENCORE ACQUISITION CO
Form 10-K
March 01, 2007

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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, 2006
	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, or a non-accelerated filer. See definition of accelerated filer and large accelerated filer in Rule 12b-2 of the Exchange Act. (Check one):

Large accelerated filer þ Accelerated filer o Non-accelerated filer 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, 2006 (the last business day of Registrant s most recently completed second fiscal quarter)	$1,324,038,526
Number of shares of Common Stock, $0.01 par value, outstanding as of February 20, 2007	53,113,534

DOCUMENTS INCORPORATED BY REFERENCE

Parts of the definitive proxy statement for the Registrant s 2007 annual meeting of stockholders are incorporated by reference into Part III of this report on Form 10-K.

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GLOSSARY OF OIL AND NATURAL GAS TERMS

The following are abbreviations and definitions of certain terms commonly used in the oil and natural gas industry and this annual report on Form 10-K (the Report):

Bbl. One stock tank barrel, or 42 U.S. gallons liquid volume, used in reference to oil or other liquid hydrocarbons.

Bcf. One billion cubic feet of natural gas.

Bbl/ D. One Bbl per day.

BOE. One barrel of oil equivalent, calculated by converting natural gas to oil equivalent barrels at a ratio of six Mcf 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.

Delay Rentals. Fees paid to the lessor of the 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 which are 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.

Encore or the Company. Encore Acquisition Company, a Delaware corporation, 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 found to be productive of 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 owner to an assignee, who assumes all or some of the burden of development, in return for an interest in the property.

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

High-Pressure Air Injection (HPAI). HPAI involves utilizing compressors to inject air 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.

Horizontal Drilling. A drilling operation in which a portion of the 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 and before removal of production from the property. Such costs include labor, superintendence, supplies, repairs, maintenance, and direct overhead charges.

LIBOR. London Interbank Offered Rate.

MBbl. One thousand Bbls.

MBOE. One thousand BOE.

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MBOE/ D. One thousand BOE per day.

Mcf. One thousand cubic feet of 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.

Mcfe/ D. One Mcfe per day.

MMBbl. One million Bbls.

MMBOE. One million BOE.

MMBtu. One million British thermal units. One British thermal unit is the amount of heat required to raise the temperature of one pound of water one degree Fahrenheit.

MMcf. One million Mcf.

MMcf/ D. One MMcf per day.

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

Net Production. Production that is owned by us less royalties and production due others.

NYMEX. New York Mercantile Exchange.

Oil. Crude oil or condensate.

Operating Income. Gross oil and natural gas revenue less applicable production, ad valorem, and severance taxes and LOE.

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

Present Value of Future Net Revenues or Present Value or PV-10. The pretax present value of estimated future revenues to be generated from the production of proved reserves, net of estimated production and future 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 and depletion, depreciation, and amortization, and discounted using an annual discount rate of 10 percent.

Productive Well. A well that produces commercial quantities of hydrocarbons, exclusive of its capacity to produce at a reasonable rate of return.

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

Proved Reserves. The estimated quantities of oil, natural gas, and natural gas liquids 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 undeveloped reserves are 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 high-pressure air injection, where such techniques have been proved effective by actual tests in the area and in the same reservoir.

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Reserve-To-Production Index (R/ P Index). An estimate expressed in years of the total estimated proved reserves attributable to a producing property divided by production from the property for the 12 months preceding the date as of which the proved reserves were estimated.

Royalty. An interest in an oil and natural gas lease that gives the owner of the interest the right to receive a portion of the production from the leased acreage (or of the proceeds of the sale thereof), but does not require the owner to pay any portion of the costs of drilling or operating the wells 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 development and production costs and future income tax expenses, discounted at 10 percent per annum to reflect the timing of future cash flows. Standardized Measure differs from PV-10 because Standardized Measure includes the effect of future income taxes.

Tertiary Recovery. An enhanced recovery operation that normally occurs after waterflooding in which chemicals or natural gasses are used as the injectant. HPAI is a form of tertiary recovery.

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.

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 and natural gas lease that gives the owner of the interest 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 costs of drilling and production operations.

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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 of Oil and Natural Gas Terms . 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. Our primary focus is 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 and Powder River Basins of Montana and North Dakota and the Paradox Basin of southeastern Utah; and
- the Mid-Continent area, which includes the Arkoma and Anadarko Basins of Oklahoma, the North Louisiana Salt Basin, the East Texas Basin, and the Barnett Shale of northern Texas.

Proved Reserves. Our estimated total proved reserves at December 31, 2006 were 153 MMbls of oil and 307 Bcf of natural gas, based on December 31, 2006 NYMEX prices of $61.06 per Bbl of oil and $5.48 per Mcf of natural gas. On a BOE basis, our proved reserves were 205 MMBOE at December 31, 2006.

Most Valuable Asset. The CCA represented approximately 59 percent of our total proved reserves as of December 31, 2006. The CCA is our most valuable asset today and in the foreseeable future. A large portion of our future success revolves around future exploitation of and production from this property through primary, secondary, and tertiary recovery techniques.

Drilling. In 2006, we drilled 91 gross operated productive wells and participated in drilling another 162 gross non-operated productive wells for a total of 253 gross productive wells for the year. On a net basis, we drilled 73.1 operated productive wells and participated in drilling another 18.6 non-operated productive wells in 2006. In 2006, we drilled 10 gross operated non-productive wells and participated in drilling another eight gross non-operated non-productive wells for a total of 18 gross non-productive wells for the year. On a net basis, we drilled 8.4 operated non-productive wells and participated in drilling another 1.8 non-operated non-productive wells in 2006. We invested $348.8 million in development and exploration activities in 2006, of which $17.3 million related to non-productive exploratory wells.

Oil and Natural Gas Reserve Replacement. During 2006, we added 20.1 MMBOE of oil and natural gas to our existing proved reserve base, which replaced 179 percent of the 11.2 MMBOE we produced in

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2006. Our average reserve replacement ratio for the three years ended December 31, 2006 is 308 percent. The following table sets forth the calculation of our reserve replacement ratios for the periods indicated:

	Year Ended December 31,			
	2006	2005	2004	Three-Year Average
	(In MBOE, except percentages)			
Acquisition Reserve Replacement Ratio				
Changes in Proved Reserves:				
Acquisitions of minerals-in-place	64	14,796	22,239	12,366
Divided by:				
Production	11,244	10,381	9,027	10,217
Acquisition reserve replacement ratio	1%	142%	246%	121%
Development Reserve Replacement Ratio				
Changes in Proved Reserves:				
Extensions, discoveries, and improved recovery	27,504	19,158	20,580	22,414
Revisions of estimates	(7,461)	(928)	(1,629)	(3,339)
Total development program	20,043	18,230	18,951	19,075
Divided by:				
Production	11,244	10,381	9,027	10,217
Development reserve replacement ratio	178%	176%	210%	187%
Total Reserve Replacement Ratio				
Changes in Proved Reserves:				
Acquisitions of minerals-in-place	64	14,796	22,239	12,366
Extensions, discoveries, and improved recovery	27,504	19,158	20,580	22,414
Revisions of estimates	(7,461)	(928)	(1,629)	(3,339)
Total reserve additions	20,107	33,026	41,190	31,441
Divided by:				
Production	11,244	10,381	9,027	10,217
Total reserve replacement ratio	179%	318%	456%	308%

During the three years ended December 31, 2006, we invested $517.6 million in acquiring proved oil and natural gas properties and leasehold acreage, and we invested an incremental $863.5 million on development, exploitation, and exploration of these and our other existing properties.

Given the inherent decline of reserves resulting from production, an oil and natural gas company must more than offset produced volumes with new reserves in order to grow. Management uses the reserve replacement ratio, as defined above, 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 that is commonly used by analysts, investors and other interested parties in the oil and gas industry as a means of evaluating the operational performance and prospects of entities engaged in the production and sale of depleting natural resources. It should be noted that the reserve replacement ratio is a statistical indicator that has limitations. As an annual measure, the ratio is limited because it typically varies widely based on the extent and timing of new discoveries and property acquisitions. Its predictive and comparative value is also limited for the same reasons. In addition, since the ratio does not consider the cost or timing of future production of new reserves, it cannot be used as a measure of value creation. The ratio does not

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distinguish between changes in reserve quantities that are developed and those that will require additional time and funding to develop.

Recent Developments

Agreement to Acquire Big Horn Basin Assets

On January 16, 2007, we entered into a purchase and sale agreement to acquire oil and natural gas producing properties and related assets in the Big Horn Basin from certain subsidiaries of Anadarko Petroleum Corporation (Anadarko), for a purchase price of $400 million, subject to customary purchase price adjustments and closing conditions. The properties are comprised of the Elk Basin Unit and the Gooseberry Unit in Park County, Wyoming. Our internal engineers have estimated that total proved reserves from these properties are approximately 20 MMBOE, which are 97 percent oil and 90 percent proved developed producing. The Big Horn Basin properties currently produce approximately 4 MBOE/ D net with an additional 350 BOE/ D net of natural gas liquids produced by the Elk Basin Gas Plant. In connection with the acquisition, we purchased put contracts on approximately two- thirds of the acquisition s expected production volumes at $65.00 per Bbl for the remainder of 2007 and all of 2008. The Big Horn Basin acquisition is expected to close in March 2007.

Agreement to Acquire Williston Basin Assets

On January 23, 2007, we entered into a purchase and sale agreement to acquire oil and natural gas producing properties in the Williston Basin from certain subsidiaries of Anadarko for a purchase price of $410 million, subject to customary purchase price adjustments and closing conditions. The properties are comprised of 50 different fields across Montana and North Dakota. Our internal engineers have estimated that total proved reserves from these properties are approximately 21 MMBOE, which are 90 percent oil and 81 percent proved developed producing. The Williston Basin properties currently produce approximately 5 MBOE/ D net, will be 85 percent operated by us and will complement our existing Rockies oil portfolio. As part of this acquisition, we are also acquiring approximately 70,000 net acres and 800 BOE/ D of production in the Bakken play in Montana and North Dakota. In connection with the acquisition, we purchased put contracts on approximately 80 percent of the acquisition s expected production volumes at an average price of $57.50 per Bbl for the remainder of 2007 and all of 2008. The Williston Basin acquisition is expected to close in April 2007.

Intention to Form a Master Limited Partnership

On January 17, 2007, we announced our intention to form a master limited partnership (MLP), that will engage in an initial public offering of common units representing limited partner interests. The MLP is expected to own certain Big Horn Basin properties to be acquired from certain subsidiaries of Anadarko and certain of our legacy oil and gas properties. We expect that the MLP will file a registration statement on Form S-1 with the SEC in the second quarter of 2007 with respect to an offering in the range of $175 million to $225 million. Any sale of common units of the MLP would be registered under the Securities Act of 1933, and such common units would only be offered and sold by means of a prospectus. This Report does not constitute an offer to sell or the solicitation of any offer to buy any securities of the MLP, and there will not be any sale of any such securities in any state in which such offer, solicitation, or sale would be unlawful prior to registration or qualification under the securities laws of such state.

Potential Divestiture of Mid-Continent Assets

We are evaluating the potential sale of certain natural gas properties in Oklahoma during 2007. The properties currently produce approximately 3,000 to 4,000 BOE/ D and have associated reserves of 15 to 25 MMBOE. No assurance can be given that a sale can be completed on terms acceptable to us.

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However, if successfully completed, we plan to use the net proceeds from the sale to reduce borrowings under our revolving credit facility.

Business Strategies

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. In order to achieve our objectives, we strive to:

Maintain an active development program. 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. We also budget a portion of internally generated cash flow to secondary and tertiary recovery projects that are longer- term in nature, the benefit from which is not seen until some point in the future.

Maximize existing reserves and production through HPAI. In addition to conventional development programs, we utilize HPAI techniques on the CCA properties to enhance our growth. HPAI involves using compressors to inject air into producing oil and natural gas formations in order to displace remaining resident hydrocarbons and force them under pressure to a common lifting point for production.

Utilize other improved recovery techniques to maximize existing reserves and production. In addition to our HPAI programs, we use secondary and other tertiary recovery techniques to increase production and proved reserves on existing properties. Throughout our CCA properties and Permian Basin properties, we have successfully used waterflood enhancement programs to increase production. Waterflood enhancement is 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. On certain non-operated properties in the Rockies, a similar tertiary recovery technique that uses carbon dioxide instead of water is being used successfully. We believe that these other improved recovery projects, including carbon dioxide injection, will continue to be a source of reserve and production growth.

Expand our reserves, production, and drilling 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 portfolio 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 drilling arrangements to explore in areas that complement our portfolio of properties. In keeping with our exploitation focus, the exploration projects expand existing fields or could set up multi-well exploitation projects if successful.

Operate in a cost effective, efficient, and safe manner. As of December 31, 2006, we operated properties representing approximately 84 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

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in a volatile commodity pricing environment, while replenishing our drilling inventory. Changing commodity prices and increased costs of goods and services affect the rate of return on a property acquisition, and the amount of our internally generated cash flow, and, in turn, can affect our capital budget. In addition to commodity price risk, we face strong competition from independents and major oil companies. Our views and the views of our competitors about future 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

We were the operator of properties representing approximately 84 percent of our proved reserves at December 31, 2006. As operator, we are able to better control expenses, capital allocation, and the timing of exploitation and development activities on our properties. We also own properties that are operated by third parties, and, as working interest owners in those properties, we are required to pay our share of operating, exploitation, and development costs. Please read Properties Nature of Our Ownership Interests below. During the years ended December 31, 2006, 2005, and 2004, our approximate costs for development activities on non-operated properties were $50.2 million, $28.2 million, and $10.9 million, respectively. We also own royalty interests in wells operated by third parties that are not burdened by lease operations expense or capital costs; however, we have little control over the implementation of projects on these properties.

Production and Price History

The following table sets forth information regarding net production of oil and natural gas, certain price information, including the effects of hedging, and average costs per BOE for the periods indicated:

	Year Ended December 31,		
	2006	**2005**	**2004**
Production:			
Oil (MBbls)	7,335	6,871	6,679
Natural gas (MMcf)	23,456	21,059	14,089
Combined (MBOE)	11,244	10,381	9,027
Average Daily Production:			
Oil (Bbls/D)	20,096	18,826	18,249
Natural gas (Mcf/D)	64,262	57,696	38,493
Combined (BOE/D)	30,807	28,442	24,665
Average Prices:			
Oil (per Bbl)	$ 47.30	$ 44.82	$ 33.04
Natural gas (per Mcf)	6.24	7.09	5.53
Combined (per BOE)	43.87	44.05	33.07
Average Costs per BOE:			
Lease operations expense	$ 8.73	$ 6.72	$ 5.30
Production, ad valorem, and severance taxes	4.43	4.39	3.36
Depletion, depreciation, and amortization	10.09	8.25	5.38
Exploration	2.71	1.39	0.44
Derivative fair value (gain) loss	(2.17)	0.51	0.56
General and administrative	2.06	1.67	1.33
Other operating expense	0.89	0.91	0.56
Oil marketing, net	0.09		

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Producing Wells

The following table sets forth information at December 31, 2006 relating to the producing wells in which we owned a working interest as of that date. Wells are classified as oil or natural gas wells according to their predominant production stream. Gross wells are the total number of producing 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, 2006, we owned a working interest in 5,775 gross wells. We also held royalty interests in units and acreage beyond the wells in which we have 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	675	89%	18	5	31%
Permian Basin	1,991	780	39%	523	240	46%
Rockies	607	315	52%	19	16	82%
Mid-Continent	388	177	46%	1,470	357	24%
Total	3,745	1,947	52%	2,030	618	30%

(a) Our total wells include 2,587 operated wells and 3,188 non-operated wells. At December 31, 2006, 61 of our wells have multiple completions.

Acreage

The following table sets forth information at December 31, 2006 relating to our acreage holdings. Developed acreage is assigned to producing 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. Our undeveloped acreage in the Rockies region represents 73 percent of our total net undeveloped acreage. Our current leases expire at various dates ranging from 2007 to 2029, with leases representing $3.2 million of cost set to expire in 2007 if not developed.

	Gross Acreage	Net Acreage
CCA:		
Developed	110,083	104,135
Undeveloped	62,465	50,956
	172,548	155,091
Permian:		
Developed	66,132	40,350
Undeveloped	15,007	13,795
	81,139	54,145

Rockies:		
Developed	64,848	39,626
Undeveloped	491,613	384,899
	556,461	424,525
Mid-Continent:		
Developed	390,869	101,023
Undeveloped	169,867	79,902
	560,736	180,925
Total:		
Developed	631,932	285,134
Undeveloped	738,952	529,552
	1,370,884	814,686

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Drilling Results

The following table sets forth information with respect to wells drilled during 2006, 2005, and 2004. The 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 found, or economic value.

	Year Ended December 31,					
	2006		2005		2004	
	Gross	Net	Gross	Net	Gross	Net
Development Wells:						
Productive	182	72	242	145	203	135
Dry holes	4	3	4	2	1	1
	186	75	246	147	204	136
Exploratory Wells:						
Productive	71	19	34	22	32	30
Dry holes	14	8	47	42	4	4
	85	27	81	64	36	34
Total:						
Productive	253	91	276	167	235	165
Dry holes	18	11	51	44	5	5
	271	102	327	211	240	170

Present Activities

As of December 31, 2006, we had a total of 12 gross (5.0 net) wells that had begun drilling and were in varying stages of drilling operations, of which 9 gross (4.7 net) were development wells. Also, there were 55 gross (23.5 net) wells that had reached total depth and were in varying stages of completion pending first production, of which 19 gross (6.2 net) wells were exploratory wells.

Delivery Commitments and Marketing

Our oil and natural gas production is principally sold to end users, marketers, refiners, and other purchasers having access to nearby pipeline facilities. In areas where there is no practical access to pipelines, oil is trucked to central storage facilities where the oil is aggregated and sold to markets out of these facilities. While we typically market our oil and natural gas production for a term of one year or less, we entered into an agreement in 2004 to sell at least 4,500 Bbls/ D at a floating market price through 2009.

For 2006, our largest purchasers included Shell Trading Company and ConocoPhillips Company, which accounted for 15 percent and 12 percent of total 2006 revenue, respectively. 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. Recently, alternative transportation routes and markets have been developed by moving a portion of the crude oil production through 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 Platte Pipeline to Wood River, Illinois as

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well as other pipelines connected to the Guernsey, Wyoming area. While shipments on Platte Pipeline are currently oversubscribed and subject to apportionment since December 2005, we were allocated transportation 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 interruption in refining throughput capacity could have a material adverse effect on our production volumes and the prices we receive for our production.

The difference between quoted 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 slightly improve in the first quarter of 2007 as compared to the fourth quarter of 2006. 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. We cannot accurately predict crude oil differentials. Natural gas differentials are expected to remain approximately constant in the first quarter of 2007 as compared to the fourth quarter of 2006. 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 independent operators and from major oil companies in acquiring properties, contracting for drilling equipment and securing trained personnel. Many of these competitors have financial and technical resources and staffs substantially larger 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 financial or personnel resources will permit.

We are also affected by competition for drilling rigs and the availability of related equipment. In the past, the oil and natural gas industry has experienced shortages of drilling rigs, equipment, pipe and personnel, which has delayed development drilling and other 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 drilling rights, and we cannot assure you that we will be able to compete satisfactorily when attempting to make further acquisitions.

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 discharged, and solid waste management. These laws and regulations may, among other things:

- require the acquisition of various permits before drilling 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 drilling, production, and transportation activities;
- restrict the way in which wastes are handled and disposed;
- limit or prohibit drilling activities on certain lands lying within wilderness, wetlands, areas inhabited by threatened of 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 increased 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 solid 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 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

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previous owners or operators whose treatment and disposal of hazardous substances, wastes, or hydrocarbons was not under our control. In fact, there is evidence that petroleum spills or releases have occurred in the past at some of the properties owned or leased by us. These properties and the substances disposed or released on them may be subject to CERCLA, RCRA, and analogous state laws. Under such laws, we could be required to remove previously disposed substances and wastes, remediate contaminated property, or perform remedial plugging or pit closure operations to prevent future contamination.

Water Discharges. The Clean Water Act and analogous state laws impose strict controls against 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. The Clean Water Act regulates storm water run-off from oil and 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. The Clean Water Act 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 the Clean Water Act 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 the Clean Water Act and analogous state laws and regulations.

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

Air Emissions. Oil and gas exploration and production operations are subject to the Federal Clean Air Act, 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 the Clean Air Act, 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 the Clean Air Act. 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.

Congress is currently considering proposed legislation directed at reducing greenhouse gas emissions . It is not possible at this time to predict how legislation that may be enacted to address greenhouse gas emissions would impact the oil and 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 the business, financial position, results of operations, and cash flows.

Activities on Federal Lands. Oil and natural gas exploration and production activities on federal lands are subject to National Environmental Policy Act (NEPA). NEPA requires federal agencies, including the Department of 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 (the OSH Act) and Other Laws and Regulation. We are subject to the requirements of the 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 the Title III of CERCLA and similar state statutes require that we organize and/or disclose information about hazardous materials used or produced in our operations. We believe that we are in substantial compliance with these applicable requirements and with other OSH Act and comparable requirements.

We believe that we are in substantial compliance with all existing environmental laws and regulations applicable to our 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. Accidental spills or releases may occur in the course of our operations, and we cannot assure you that we will not 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, results of operations or ability to make distributions to you.

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.

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

Natural Gas Regulation. The availability, terms, and cost of transportation significantly affect sales of natural gas. The interstate transportation and sale for resale of natural gas is subject to federal regulation, including regulation of the terms, conditions and rates for interstate transportation, storage and various other matters, primarily by the Federal Energy Regulatory Commission (the FERC). Federal and state regulations govern the price and terms for access to natural gas pipeline transportation. The FERC s regulations for interstate natural gas transmission in some circumstances may also affect the intrastate transportation of natural gas.

Although natural gas prices are currently unregulated, Congress historically has been active in the area of natural gas regulation. We cannot predict whether new legislation to regulate natural gas might be proposed, what proposals, if any, might actually be enacted by Congress or the various state legislatures, and what effect, if any, the proposals might have on the operations of the underlying properties. Sales of condensate and natural gas liquids are not currently regulated and are made at market prices.

State Regulation. The various states regulate the drilling for, and the 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, such as new wells, renewed wells, and tertiary production.

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 there can be no assurance that they will not 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.

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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 operations. Any of these problems could 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 236 employees as of December 31, 2006, 80 of which were field personnel. None of the employees are represented by any union. We consider our relations with our employees to be good.

Principal Executive Office

We are a Delaware corporation with our headquarters in Texas. Our principal executive offices are located at 777 Main Street, Suite 1400, Fort Worth, Texas 76102. Our main telephone number is (817) 877-9955.

Available Information

We make available electronically, free of charge through our website (www.encoreacq.com), our annual reports on Form 10-K, quarterly reports on Form 10-Q, current reports on Form 8-K, and other items filed 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 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 officer and principal financial officer. The code of business conduct and ethics is available on our Internet website (www.encoreacq.com). 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 (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 2006, we submitted to the NYSE the CEO certification required by Section 303A.12(a) of the NYSE s Listed Company Manual. In 2007, we expect to submit this certification to the NYSE after the 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 the code of business conduct and ethics and Board committee charters are also available in print upon written request to the Corporate Secretary, Encore Acquisition Company, 777 Main Street, Suite 1400, Fort Worth, Texas 76102.

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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 in our principal areas of operation:

	2006 Net Production				Proved Reserve Quantities at December 31, 2006			PV-10 at December 31, 2006	
	Oil	Natural Gas	Total	Percent	Oil	Natural Gas	Total	Amount(a)	Percent
	(MBbls)	(MMcf)	(MBOE)		(MBbls)	(MMcf)	(MBOE)	(in thousands)	
CCA	4,851	1,330	5,073	45%	117,868	15,750	120,493	$ 1,113,352	57%
Permian Basin	1,277	5,841	2,250	20%	23,105	106,693	40,887	302,669	15%
Rockies	732	360	792	7%	8,716	2,895	9,198	426,160	22%
Mid-Continent	475	15,925	3,129	28%	3,745	181,426	33,983	119,035	6%
Total	7,335	23,456	11,244	100%	153,434	306,764	204,561	$ 1,961,216	100%

(a) Calculated as the pretax present value of estimated future revenues to be generated from the production of proved reserves, net of estimated production and future development costs, using prices and costs as of the date of estimation without future escalation, without giving effect to hedging activities and non-property related expenses such as general and administrative expenses, debt service, and depletion, depreciation, and amortization; and discounted using an annual discount rate of 10 percent. Giving effect to hedging transactions, our PV-10 value would have been decreased by $21.7 million at December 31, 2006.

The Standardized Measure at December 31, 2006 is $1.5 billion. Standardized Measure differs from PV-10 by $499.4 million because Standardized Measure includes the effect 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 relative value of each of our areas.

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. Reserve engineering is a subjective process of estimating recoverable amounts of underground accumulations of oil and natural gas that cannot be measured in an exact way. The accuracy of any reserve estimate depends on the quality of available data and the interpretation of that data by petroleum engineers. In addition, the results of drilling, testing, and production activities may require revisions of estimates that were made previously. Accordingly, estimates of reserves and their value are inherently imprecise and are subject to constant revision and change, and they 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.

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During 2006, we filed estimates of oil and natural gas reserves at December 31, 2005 with the U.S. Department of Energy on Form EIA-23. As required for the EIA-23, the filing reflected only production that comes from our operated wells at year end, and is reported on a gross basis. 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 on June 1, 1999, and we have subsequently acquired additional working interests from various owners. Presently, we operate 99.7 percent of our CCA properties with an average working interest of approximately 89 percent in the oil wells and 31 percent in the gas wells. The average daily production from our CCA properties during 2006 was 13,898 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 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.

Since taking over operations, our net production from the CCA has increased by approximately 80 percent from 7,807 BOE/ D (average for June 1999) to 14,032 BOE/ D (average for the fourth quarter of 2006). We have accomplished ongoing production growth through a combination of:

- acquisition of additional interests;
- effective management of the existing wellbores;

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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 2006, we drilled 33 gross wells on the CCA, of which 11 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 $103.9 million, $121.7 million, and $116.5 million in capital projects on the CCA during 2006, 2005, and 2004, respectively.

Our outlook for CCA production growth remains strong. We plan to continue the development of the reserve base using the same strategies that gave rise to our past success with this property.

As outlined above, the CCA represents approximately 59 percent of our total proved reserves as of December 31, 2006. The CCA represents our most valuable asset today and in the foreseeable future. A large portion of our future success revolves around current and future projects on these properties.

We began implementation of two new improved waterfloods in the CCA in 2006. One in South Pine Unit in the Red River U4 and one in the Coral Creek Unit in the Red River U4. We believe these projects have added significant reserves in the Red River U4 and expect to see results in early 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 believe that HPAI technology can be applied to other units in the CCA and that it may yield significant new reserves.

In the Pennel unit, we are currently injecting 36 MMcf/ D of high pressure from our new HPAI injection facility completed in April 2005. The HPAI facility is capable of injecting 60 MMcf/ D of high pressure air into the Pennel unit, giving us the capacity to complete the development of this unit and potentially expand to the Coral Creek unit to the South. The Pennel unit is responding to the air injection below our original production expectations, with an increase of approximately 400 BOE/ D over the expected production decline prior to the initiation of the project. In the Little Beaver unit of the CCA we are currently injecting 18 MMcf/ D of high pressure air. We continue to see positive production response, with an increase of approximately 800 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.

Net Profits Interests (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 drilling 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

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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 2006, 2005, and 2004, we reduced revenue for NPI payments by $23.4 million, $21.2 million, and $12.6 million, respectively.

Permian Basin Properties West Texas and New Mexico

Average daily production for our Permian Basin properties in the fourth quarter of 2006 was 5,940 BOE/ D. We believe these properties will be an area of growth over the next several years. During 2006, we invested approximately $63.8 million of development capital on our Permian Basin properties.

West Texas

Our Permian Basin 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, Glorietta, Clearfork, Wolfcamp, and Pennsylvanian zones. Production from the southern portion of the Permian Basin comes mainly from the Canyon and Strawn formations with multiple pay intervals.

Continued development opportunities remain on these properties. During 2006, we drilled 43 gross wells on the West Texas Permian 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 future 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.

In April 2006, we commenced drilling in the development areas and by June 2006 operated four drilling rigs. A total of 24 wells were drilled during 2006, of which 12 were commitment wells. By the end of the year, we had fulfilled our obligation in two development areas (Brown Bassett Wolfcamp and Wilshire Devonian).

In 2007, we intend to drill approximately 50 wells, 12 of which are commitment wells, and invest approximately $65 million of net capital in the development areas. We anticipate operating six rigs in West Texas by the end of 2007.

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New Mexico

The New Mexico region was established in May 2006 with the strategy of deploying capital to develop low to medium risk drilling projects in southeastern New Mexico where multiple reservoir targets are available. The region expects to grow reserves through:

Entering into joint ventures;

Agreements with major oil and gas companies;

Drill to earn agreements;

Farm-outs of close-in exploitation opportunities; and

Establish 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. In 2006, we drilled three operated wells and participated in two non-operated wells. The first well was drilled in August 2006 and it encountered three potential pay intervals. We own an 85 percent working interest in this well. The second well is 100 percent owned by us and is currently waiting on pipeline connection.

We believe this region will be one of growth and opportunity. We expect to increase the value of the New Mexico region through conventional infill drilling opportunities throughout 2007.

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

Oklahoma, Arkansas, North Texas, 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. These properties produce primarily natural gas and, to a lesser extent, oil from various horizons. We also have operated interests in properties producing from the Barnett Shale in northern Texas and the Hugoton Basin in Kansas.

Average daily production for these properties increased approximately 20 percent from 25,317 Mcfe/ D in the fourth quarter of 2005 to 30,430 Mcfe/ D for the fourth quarter of 2006.

During 2006, we drilled 129 wells and invested $125.5 million of development and exploration capital in these properties.

We are planning to evaluate the potential sale of certain natural gas properties in Oklahoma during 2007. The properties currently produce approximately 3,000 to 4,000 BOE/ D and have associated reserves of 15 to 25 MMBOE. No assurance can be given that a sale can be completed on terms acceptable to the Company. However, if successfully completed, we plan to use the net proceeds from the sale to reduce borrowings under our revolving credit facility.

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. 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.

The Overton Field assets are in the same core area as our interests in Elm Grove field and have similar geology. The properties are producing primarily from multiple tight sandstone reservoirs in the

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Travis Peak and Lower Cotton Valley formations at depths ranging between 8,000 and 11,500 feet. Estimated proved reserves are approximately 94 percent natural gas, and the properties are 100 percent operated by us.

During 2006, we drilled 60 gross wells and invested approximately $44.4 million of capital to develop these properties. Average daily production for this region decreased 18 percent from 25,800 Mcfe/ D in the fourth quarter of 2005 to 21,092 Mcfe/ D for the fourth quarter of 2006.

Rocky Mountain Properties North Dakota, Montana, and Utah

Williston Basin North Dakota and Montana

The Williston Basin properties consist 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. The average daily production from the Williston Basin properties was 978 BOE/ D for the fourth quarter of 2006. During 2006, we invested approximately $0.7 million of capital to develop these properties.

Bell Creek Montana

The Bell Creek properties are located in the Powder River Basin of southeastern Montana. We operate the 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 invested $2.8 million of capital in these properties in 2006. The average daily production from the Bell Creek properties was 453 BOE/ D during the fourth quarter of 2006. We have initiated a pilot polymer injection program on our Bell Creek properties. We inject a polymer into an injection well to reduce the amount of water injection needed to recover oil. The polymer injection process also redirects the injected water into new pathways to produce oil previously by passed by the original waterflood. This process, coupled with polymer treatments to oil producers, makes for a more efficient recovery of oil than standard waterflooding. Our polymer pilot, if successful, will be expanded in phases. We expect to see results from our pilot project by early 2008.

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. Our average net production from the properties for the fourth quarter of 2006 was approximately 704 BOE/ D. We believe these properties have potential horizontal redevelopment, secondary development, and tertiary recovery potential. Our development capital for these properties was $5.0 million during 2006.

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 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 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*

You should read carefully the following factors and all other information contained in this Report. If any of the risks and uncertainties described below or elsewhere in this Report actually 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 may lose all or part of his investment.

Oil and natural gas prices are volatile and sustained periods of low 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;
- armed conflict in oil and natural gas producing countries;
- 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; and
- the price and availability of alternative fuels.

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Our revenue, profitability, and cash flow depend upon the prices and demand for oil and natural gas, and a drop in prices can significantly affect our financial results and impede or stop 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;
- limit our ability to borrow money or raise additional capital; and
- impair our ability to pay distributions.

In addition, the prices that we receive for our oil and natural gas production usually trade at a discount to the relevant benchmark prices, such as NYMEX. 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. We cannot accurately predict future differentials.

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 recoverable amounts of underground accumulations of oil and natural gas and assumptions concerning future oil and natural gas prices, 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:

- future oil and natural gas prices;
- production levels;
- capital expenditures;
- operating and development costs;
- the effects of regulation; and
- availability of funds.

If these assumptions prove to be incorrect, our estimates of reserves, the economically recoverable quantities of oil and natural gas attributable to any particular group of properties, the 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 unhedged oil prices and is determined 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 drilling 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 present value of future net cash flows from 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. However, actual future net cash flows from our oil and natural gas properties also will be affected by factors such as:

- the actual prices we receive for oil and natural gas;
- our actual operating costs in producing oil and natural gas;
- the amount and timing of actual production;
- the amount and timing of our capital expenditures;
- supply of and demand for oil and natural gas; and
- changes in governmental regulations or taxation.

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 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.

The failure to replace our reserves could adversely affect our financial condition.

Our future success depends upon our ability to find, develop, or acquire additional oil and natural gas reserves that are economically recoverable. Our proved reserves generally decline when reserves are produced, unless we conduct successful exploitation, development, or exploration activities or acquire properties containing proved reserves, or both. We may not be able to find, develop, or acquire additional reserves on an economic basis.

Substantial capital is required to replace and grow reserves. If lower oil and natural gas prices or operating difficulties result in our cash flow from operations being less than expected or limit our ability to borrow under our revolving credit facility, we may be unable to expend the capital necessary to find, develop, or acquire new oil and natural gas 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.

We may be required to write down our asset carrying values.

We may be required to write down the carrying value of our oil and natural gas properties if:

- oil and natural gas prices decrease;
- we make substantial downward adjustments to our estimated proved reserves;
- our operating expenses or development costs increase substantially; or
- we experience poor performance from our development and exploitation activities.

We capitalize the costs to acquire, find, and develop our oil and natural gas properties under the successful efforts accounting method. We review the carrying value of our properties quarterly, based on

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changes in expectations of future oil and natural gas prices, expenses, tax rates, and other factors. To the extent such reviews indicate a reduction of the estimated useful life or estimated future cash flows of our assets, the carrying value may not be recoverable and therefore require a write-down. We may incur impairment charges in the future, which 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 may 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;
- outbid by competitors; or
- unable to obtain necessary regulatory approvals.

In making acquisitions, we must make a number of important assumptions regarding, among other things, the following:

- expected revenues;
- the level of recoverable reserves and production;
- future oil and natural gas prices;
- operating costs; and
- the nature and amount of potential environmental and other liabilities.

The accuracy of these assessments is inherently uncertain. In connection with these assessments, we perform a review of the subject properties that we believe to be generally consistent with industry practices. Our review will not reveal all existing or potential problems nor will it permit us to become sufficiently familiar with the properties to fully assess their deficiencies and capabilities. Inspections may not always be performed on every well, and structural and environmental problems are not necessarily observable even when an inspection is undertaken. Even when problems are identified, the seller may be unwilling or unable to provide effective contractual protection against all or part of the problems. We are often not entitled to contractual indemnification for environmental liabilities and acquire properties on an as is basis.

Future acquisitions, including the proposed Big Horn Basin and Williston Basin 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 operating results. 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.

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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.

The process of integrating acquired operations into our existing operations, including the proposed Big Horn Basin and Williston Basin acquisitions, 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.

A substantial portion of our producing properties is located in one geographic area.

We have extensive operations in the Williston Basin of Montana and North Dakota. As of December 31, 2006, our CCA properties in the Williston Basin represented approximately 59 percent of our proved reserves and 45 percent of our 2006 production. Any circumstance or event that negatively impacts production or marketing of oil and natural gas in the Williston Basin would materially reduce our earnings and cash flow.

Derivative instruments expose us to risks of financial loss in a variety of circumstances.

We use derivative instruments in an effort to mitigate the negative effects of declining commodity prices. 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 nominal amount that is subject to 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 our sale or purchase 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 resulting in either a drop in the price we receive for production that is not offset by an increase in cash inflows from the derivative or vice versa.

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

During July 2006, we elected to discontinue hedge accounting prospectively for all commodity derivatives which were previously accounted for as hedges. While this change has no effect on cash flows, results of operations are affected by mark-to-market gains and losses, which fluctuate with the swings in oil and natural gas prices.

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

Other companies operate some of the properties in which we have an interest. 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 drilling or acquisition activities and lead to unexpected future costs.

Drilling for 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 drilling, completing, and operating a well is often uncertain, and many 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 enough oil and natural gas to be commercially viable after drilling, operating and other costs. Furthermore, our drilling and producing operations may be curtailed, delayed, or canceled as a result of other factors, including:

- high costs, shortages or delivery delays of drilling rigs, equipment, labor, or other services;
- unexpected operational events and drilling conditions;
- reductions in oil and natural gas prices;
- limitations in the market for oil and natural gas;
- adverse weather conditions;
- facility or equipment malfunctions;
- equipment failures or accidents;
- title problems;
- pipe or cement failures;
- 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 drilling and service tools;
- unusual or unexpected geological formations;
- loss of drilling fluid circulation;
- pressure or irregularities in formations;
- fires;

- natural disasters;
- blowouts, surface craterings and explosions; and
- uncontrollable flows of oil, natural gas or well fluids.

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

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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 do not maintain insurance against the loss of oil or natural gas reserves as a result of operating hazards, nor do we maintain business interruption insurance. In addition, pollution and environmental risks generally are not fully insurable. We may experience losses for uninsurable or uninsured risks or losses in amounts in excess of existing insurance coverage. The occurrence of an event that is not fully covered by insurance could harm our 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 operations. 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.

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 adopted a $285 million capital budget for 2007, excluding acquisitions. We intend to finance these capital expenditures through a combination of cash flow from operations 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 drilling and other activities or be forced to sell some of our assets on an untimely or unfavorable basis.

The loss of key personnel could adversely affect our business.

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 Mr. I. Jon Brumley, Mr. Jon S. Brumley, or other key personnel 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 drilling 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 some 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 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.

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.

We operate in the highly competitive areas of oil and natural gas acquisition, development, exploitation, and production. The oil and natural gas industry is characterized by rapid and significant technological advancements and introductions of new products and services using new technologies. We face intense competition from independent, technology-driven companies as well as from both major and other independent oil and natural gas companies in each of the following areas:

- acquiring desirable producing properties or new leases for future exploration;
- marketing our oil and natural gas production;
- integrating new technologies; and
- acquiring the equipment and expertise necessary to develop and operate our properties.

Many of our competitors have financial, technological, and other resources substantially greater than ours, which may adversely affect our ability to compete with these companies. These companies may be able to pay more for development prospects and productive oil and natural gas properties and may be able to define, evaluate, bid for, and purchase a greater number of properties and prospects than our financial or human resources permit. Further, these companies may enjoy technological advantages and may be able to implement new technologies more rapidly than we can. Our ability to develop and exploit our oil and natural gas properties and to acquire additional properties in the future will depend upon our ability to successfully conduct operations, implement advanced technologies, evaluate and select suitable properties, and consummate transactions in this highly competitive environment.

We are subject to complex federal, state, and local laws and regulations that could adversely affect our business.

Exploration, development, production, and sale of oil and natural gas in North America are subject to extensive federal, state, and local laws and regulations. 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 be required to make large expenditures to comply with applicable laws and regulations, which could adversely affect our results of operations and financial condition. Matters subject to regulation include discharge permits for drilling operations, drilling bonds, spacing of wells, unitization and pooling of properties, environmental protection, reports concerning operations, and taxation.

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We may incur significant costs and liabilities as a result of environmental and safety requirements applicable to our oil and natural gas exploration and production activities. These costs and liabilities could arise under a wide range of federal, state, and local environmental and safety laws and regulations, including regulations and enforcement policies, which have tended to become increasingly strict over time. Failure to comply with these laws and regulations may result in the assessment of administrative, civil, and criminal penalties, imposition of cleanup and site restoration costs and liens, and to a lesser extent, issuance of injunctions to limit or cease operations. In addition, claims for damages to persons or property may result from environmental and other impacts of our operations. We do not believe that full insurance coverage for all potential environmental damages is available at a reasonable cost, and we may need to expend significant financial and managerial resources to comply with environmental regulations and permitting requirements. We could incur substantial additional costs and liabilities in our oil and natural gas operations as a result of stricter environmental laws, regulations, and enforcement policies.

Failure to comply with these laws and regulations also may result in the suspension or termination of our operations and subject us to administrative, civil, and criminal penalties. Further, these laws and regulations could change in ways that substantially increase our costs. Any of these liabilities, penalties, suspensions, terminations, or regulatory changes could make it more expensive for us to conduct our business or cause us to limit or curtail some of our operations.

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

As of December 31, 2006, we had total debt of $661.7 million and stockholders equity of $816.9 million. Together with our subsidiaries, we may incur substantially more debt in the future. Although our revolving credit facility and the indentures governing our senior subordinated notes contain restrictions on our incurrence of additional indebtedness, these restrictions are subject to a number of qualifications and exceptions, and under certain circumstances, indebtedness incurred in compliance with these restrictions could be substantial. Also, these restrictions do not prevent us from incurring obligations that do not constitute indebtedness. As of December 31, 2006, we had $460.9 million of available borrowing capacity under our revolving credit facility, subject to specific requirements, including compliance with financial covenants.

We recently announced agreements to acquire producing properties and related assets in the Big Horn Basin and Williston Basin from subsidiaries of Anadarko for an aggregate purchase price of $810 million, subject to customary purchase price adjustments. We initially intend to fund the acquisition of these properties and related assets through additional borrowings under one or more credit facilities. Our future debt reduction efforts will be subject to numerous risks and uncertainties, and there can be no assurances that such efforts will be successful.

Our debt level could have several important consequences to you, including:

- we may have difficulties borrowing money in the future for acquisitions, to meet our operating expenses, or for other purposes;

- the amount of our interest expense may increase because certain of our borrowings are at variable rates of interest, which, if interest rates increase, could result in higher interest expense;

- we will need to use a portion of the money we earn to pay principal and interest on our debt, which will reduce the amount of money we have to finance our operations and other business activities;

- we may be more vulnerable to economic downturns and adverse developments in our industry; and

- our debt level could limit our flexibility in planning for, or reacting to, changes in our business and industry.

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Our ability to meet our expenses and debt obligations will depend on our future performance, which will be affected by financial, business, economic, regulatory, and other factors, many of which are beyond our control. Our earnings may not be sufficient to allow us to pay the principal and interest on our debt and meet our other obligations. If we do not have enough money to pay our debts, we may be required to refinance all or part of our existing debt, sell assets, borrow more money, or raise equity, which we may not be able to do on terms acceptable to us, if at all. Further, failing to comply with the financial and other restrictive covenants in our debt agreements could result in an event of default under such indebtedness, which could adversely affect our business, financial condition, and results of operations.

ITEM 1B. *UNRESOLVED STAFF COMMENTS*

There were no unresolved SEC staff comments as of December 31, 2006.

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 us.

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

There were no matters submitted to stockholders during the fourth quarter of 2006.

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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 quarterly high and low sales prices of our common stock for each quarterly period of 2006 and 2005, as adjusted retroactively to reflect a 3-for-2 stock split that occurred on July 12, 2005:

	High	Low
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
2005		
Quarter ended December 31	$ 39.37	$ 29.69
Quarter ended September 30	39.48	28.63
Quarter ended June 30	29.63	22.12
Quarter ended March 31	30.48	21.44

On February 20, 2007, the closing sales price of our common stock as reported by the NYSE was $24.99 per share. On February 20, 2007, we had approximately 286 shareholders of record.

Issuer Purchases of Equity Securities

The following table summarizes purchases of our common stock during the fourth quarter of 2006:

Month	Total Number of Shares Purchased	Average Price Paid per Share	Total Number of Shares Purchased as Part of Publicly Announced Plans or Programs	Maximum Number of Shares That May Yet Be Purchased Under the Plans or Programs
October		$		NA
November(a)	17,809	$ 25.69		NA
December		$		NA
Total	17,809	$ 25.69		NA

(a) We do not have a formal common stock repurchase program. During the fourth quarter of 2006, certain employees surrendered shares of common stock to pay income tax withholding obligations in conjunction with vesting of restricted shares under our 2000 Incentive Stock Plan.

Dividends

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

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Stock Performance Graph

The following graph compares our cumulative total stockholder return during the period from January 1, 2002 to December 31, 2006 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, 2002 and that all dividends 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, 2002 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 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)				
	2006	2005	2004	2003	2002
	(In thousands, except per share and per unit data)				
Consolidated Statements of Operations Data:					
Revenues(a):					
Oil	$ 346,974	$ 307,959	$ 220,649	$ 176,351	$ 134,854
Natural gas	146,325	149,365	77,884	43,745	25,838
Oil marketing(e)	147,563				
Total revenues	$ 640,862	$ 457,324	$ 298,533	$ 220,096	$ 160,692
Net income	$ 92,398	$ 103,425(b)	$ 82,147	$ 63,641(c)	$ 37,685
Net income per common share(d):					
Basic	$ 1.78	$ 2.12	$ 1.74	$ 1.41	$ 0.84
Diluted	1.75	2.09	1.72	1.40	0.83
Weighted average number of common shares outstanding(d):					
Basic	51,865	48,682	47,090	45,153	45,047
Diluted	52,736	49,522	47,738	45,500	45,242
Consolidated Statements of Cash Flows Data:					
Cash provided by (used in):					
Operating activities	$ 297,333	$ 292,269	$ 171,821	$ 123,818	$ 91,509
Investing activities	(397,430)	(573,560)	(433,470)	(153,747)	(159,316)
Financing activities	99,206	281,842	262,321	17,303	80,749
Production:					
Oil (Bbls)	7,335	6,871	6,679	6,601	6,037
Natural gas (Mcf)	23,456	21,059	14,089	9,051	8,175
Combined (BOE)	11,244	10,381	9,027	8,110	7,399
Average Sales Price:					
Oil ($/Bbl)	$ 47.30	$ 44.82	$ 33.04	$ 26.72	$ 22.34
Natural gas ($/Mcf)	6.24	7.09	5.53	4.83	3.16
Combined ($/BOE)	43.87	44.05	33.07	27.14	21.72
Average Costs per BOE:					
Lease operations(f)	$ 8.73	$ 6.72	$ 5.30	$ 4.70	$ 4.15
Production, ad valorem, and severance taxes	4.43	4.39	3.36	2.71	2.12
Depletion, depreciation, and amortization	10.09	8.25	5.38	4.13	4.67
Exploration(f)	2.71	1.39	0.44		

General and administrative(f)	2.06	1.67	1.33	1.12	0.83
Derivative fair value (gain) loss(g)	(2.17)	0.51	0.56	(0.11)	(0.12)
Other operating expense	0.89	0.91	0.56	0.43	0.28
Oil marketing, net(e)	0.09				

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	Year Ended December 31,(h)				
	2006	2005	2004	2003	2002
	(In thousands, except per share and per unit data)				
Reserves:					
Oil (Bbls)	153,434	148,387	134,048	117,732	111,674
Natural gas (Mcf)	306,764	283,865	234,030	138,950	99,818
Combined (BOE)	204,561	195,698	173,053	140,890	128,310

	As of December 31,				
	2006	2005	2004	2003	2002
	(In thousands)				
Consolidated Balance Sheets Data:					
Working capital	$ (40,745)	$ (56,838)	$ (15,566)	$ (52)	$ 12,489
Total assets	2,006,900	1,705,705	1,123,400	672,138	549,896
Total debt	661,696	673,189	379,000	179,000	166,000
Stockholders equity	816,865	546,781	473,575	358,975	296,266

(a) For the years ended December 31, 2006, 2005, 2004, 2003, and 2002 we reduced revenue for NPI payments by $23.4 million, $21.2 million, $12.6 million, $5.8 million, and $2.0 million, respectively.

(b) Net income for the year ended December 31, 2005 includes an after-tax loss on early redemption of debt of $12.2 million, which affects its comparability with other periods presented.

(c) Net income for the year ended December 31, 2003 includes $0.9 million income from the cumulative effect of accounting change, net of tax, which affects its comparability with other periods presented.

(d) Net income per common share and the weighted-average number of common shares outstanding have been revised for years prior to 2005 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.

(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 stock-based compensation expense in all prior periods presented has been reclassified to allocate the amount to the same respective income statement lines as the employees salary, cash bonus, and benefits. 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 commodity derivatives which were previously accounted for as hedges. From that point forward, all mark-to-market gains or losses on these derivative instruments are recorded in Derivative fair value (gain) loss while in periods prior to that point, only the ineffective portions of hedges were recorded in Derivative fair value (gain) loss .

(h) We acquired Crusader Energy Corporation (Crusader) in October 2005 and Cortez Oil & Gas, Inc. (Cortez) in April 2004. The operating results or these entities are included in our Consolidated Statements of Operations from the date of acquisition forward.

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

The following discussion and analysis of our consolidated financial position and results of operations should be read in conjunction with our financial statements and 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. The words anticipate , estimate , expect , project , intend , plan , believe and similar expressions identify forward-looking statements. Actual results could differ materially from those stated in the forward-looking statements. We do not undertake to update, revise, or correct any of the forward-looking information unless required to do so under federal securities laws. Readers are cautioned that such forward-looking statements should be read in conjunction with our disclosures under the headings: Information Concerning Forward-Looking Statements below and Item 1A. Risk Factors .

Introduction

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

- Overview of Business
- 2006 Highlights
- 2007 Outlook
- Results of Operations
  - Comparison of 2006 to 2005
  - Comparison of 2005 to 2004
- Capital Resources
- Capital Commitments
- Liquidity
- Off-Balance Sheet Arrangements
- Inflation and Changes in Prices
- Critical Accounting Policies and Estimates
- New Accounting Pronouncements
- Information Concerning Forward-Looking Statements

Overview of Business

We engage 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;
- Maximizing existing reserves and production through HPAI;

Utilizing other improved recovery techniques to maximize existing reserves and production;

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

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Exploring for reserves; and

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

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 2006, with average NYMEX prices increasing in each of the past three years. However, our oil wellhead differentials to NYMEX widened somewhat in 2006 as we realized 82 percent of the average NYMEX oil price. Natural gas prices deteriorated in 2006 as compared to 2005, but average NYMEX prices remain higher than historical averages. Natural gas prices were at an all-time high in 2005 with an average front month NYMEX price of $8.96 per Mcf. The market softened somewhat in 2006 with the average NYMEX price for the year of $6.11 per Mcf, though our differentials strengthened as we realized 94 percent of the average NYMEX natural gas price. Commodity prices are influenced by many factors that are outside of our control. We cannot 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 future production.

During 2006, we did not make a significant acquisition of proved reserves. Instead, we acquired unproved acreage in our core areas and continued to make significant investments within our core areas to develop proved undeveloped reserves and increase production from proved developed reserves through various secondary and tertiary recovery techniques, including our HPAI program in the CCA. See 2007 Outlook below for discussion of significant acquisitions since year-end.

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 2006, we replaced 179 percent of our 2006 production primarily as a result of drilling and improved recovery success. Please read Items 1 and 2. Business and Properties General Oil and Natural Gas Reserve Replacement for the calculation of our reserve replacement ratios.

We continue to see positive results from our Phase 1 and 2 of our CCA HPAI project, although results were about 300 Bbls below our original expectations as a result of (1) a lack of sustained air injection due to delays in converting injection wells, (2) faulty seal assemblies in injection wells, and (3) different reservoir qualities and characteristics throughout the fields. Our independent reserve engineers, Miller and Lents, estimated that we added 7.0 MMBbls, 3.2 MMBbls, and 9.1 MMBbls of proved oil reserves associated with our HPAI program during 2006, 2005, and 2004, respectively. Over the long term, we believe that HPAI technology can be successfully applied throughout the CCA.

2006 Highlights

Our financial and operating results for 2006 include the following:

Oil and natural gas reserves increased five percent to 205 MMBOE. During 2006, we added 20.1 MMBOE, replacing 179 percent of the 11.2 MMBOE produced in 2006. Please read Items 1 and 2. Business and Properties General Oil and Natural Gas Production and Reserves for the calculation of our reserve replacement ratios. At December 31, 2006, oil reserves accounted for 75 percent of total proved reserves, and 65 percent of proved reserves are developed. However, primarily as a result of a decline in natural gas prices, the estimated pretax present value of our reserves decreased by 27 percent to $2.0 billion (using a 10 percent discount rate and constant year end prices of $61.06 for oil and $5.48 for natural gas). The Standardized Measure at December 31, 2006 was $1.5 billion. Standardized Measure differs from PV-10 by $499.4 million, because Standardized Measure includes the effect of future income taxes.

During 2006, we had oil and natural gas revenues of $493.3 million. This represents an eight percent increase over the $457.3 million of oil and natural gas revenues reported in 2005.

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Our realized average oil price for 2006, including the effects of hedging, increased $2.48 per Bbl to $47.30 per Bbl as compared to $44.82 per Bbl in 2005. Average oil differentials more than doubled in 2006 to $11.80 per Bbl as compared to $5.50 per Bbl in 2005, which somewhat offset higher production volumes and higher wellhead prices. Our realized average natural gas price for 2006, including the effects of hedging, decreased $0.85 per Mcf to $6.24 per Mcf as compared to $7.09 per Mcf in 2005.

Production volumes for 2006 increased eight percent to 30,807 BOE/ D (11.2 MMBOE), compared with 2005 production volumes of 28,442 BOE/ D (10.4 MMBOE). The rise in production volumes was attributable to our drilling program, HPAI uplift, and acquisitions completed in the second half of 2005. Oil represented 65 percent and 66 percent of our total production volumes in 2006 and 2005, respectively.

During 2006, we generated cash flows from operating activities of $297.3 million. This represents a five percent increase over the $292.3 million of cash flows from operating activities we reported for 2005.

On April 4, 2006, we closed a public offering of 4.0 million shares of common stock at a price of $32.00 per share. The net proceeds of the offering, after deducting underwriting discounts and commissions and the expenses of the offering, were $127.1 million. We used the net proceeds to reduce the amounts outstanding under our revolving credit facility, invest in oil and natural gas activities, and to pay general corporate expenses.

We reported net income of $92.4 million, or $1.75 per diluted share, in 2006, as compared to $103.4 million, or $2.09 per diluted share, for 2005. In addition to the increase in the effective tax rate that decreased net income by $4.7 million, the decrease in net income was primarily due to the following pretax items:

- Our natural gas wellhead price was $1.28 per Mcf less in 2006 than 2005 which negatively impacted revenues and margins;

- Increased service costs, expensing of stock options, high operating costs in the Mid-Continent area, and expensing of HPAI costs for LOE in 2006 resulted in an increase of $28.5 million, or $2.01 per BOE;

- DD&A per BOE increased to $10.09 per BOE as compared to $8.25 per BOE in 2005 as a result of higher than historical finding and development costs, which added $27.8 million to total DD&A;

- Exploration expense was $16.1 million higher due to a larger exploration program in 2006 than 2005; and

- Interest expense increased by $11.1 million in 2006 as compared to 2005 as a result of higher average debt levels due to financing acquisitions and our capital program.

Partially offsetting the above items, the change in net income was positively impacted by the following pretax items:

- Derivative fair value gain increased $29.8 million, primarily as a result of our discontinuance of hedge accounting in July 2006; and

- The recognition of a $19.5 million loss on the early redemption of debt in 2005.

Diluted earnings per share were lower as a result of the above items and the aforementioned public offering of common stock in April.

We entered into a joint development agreement with ExxonMobil to develop seven natural gas fields in West Texas. Under the terms of the agreement, we have the opportunity to develop

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approximately 100,000 gross acres and will earn 30 percent of ExxonMobil s working 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. In 2006, we drilled 24 wells, 12 of which were commitment wells, with an investment of $29.5 million under the joint development agreement. At December 31, 2006, we had advanced $22.4 million to ExxonMobil for its portion of drilling these commitment wells.

We invested $377.6 million in oil and natural gas activities during 2006 (excluding asset retirement obligations of $0.9 million). Of this amount, we invested $348.7 million in development, exploitation, HPAI expansion, and exploration activities, which yielded 253 gross (91.6 net) productive wells, and $28.9 million on acquisitions primarily of undeveloped leases. We operated between 9 and 12 rigs during 2006, including 4 rigs related to our west Texas joint development agreement.

2007 Outlook

On January 16, 2007, we entered into a purchase and sale agreement to acquire oil and natural gas producing properties and related assets in the Big Horn Basin from certain subsidiaries of Anadarko, for a purchase price of $400 million, subject to customary purchase price adjustments and closing conditions. The properties are comprised of the Elk Basin Unit and the Gooseberry Unit in Park County, Wyoming. Our internal engineers have estimated that total proved reserves from these properties are approximately 20 MMBOE, which are 97 percent oil and 90 percent proved developed producing. The Big Horn Basin properties currently produce approximately 4 MBOE/ D net with an additional 350 BOE/ D net of natural gas liquids produced by the Elk Basin Gas Plant. In connection with the acquisition, we purchased put contracts on approximately two-thirds of the acquisition s expected production volumes at $65.00 per Bbl for the remainder of 2007 and all of 2008. The Big Horn Basin acquisition is expected to close in March 2007.

On January 23, 2007, we entered into a purchase and sale agreement to acquire oil and natural gas producing properties in the Williston Basin from certain subsidiaries of Anadarko for a purchase price of $410 million, subject to customary purchase price adjustments and closing conditions. The properties are comprised of 50 different fields across Montana and North Dakota. As part of this acquisition, we are also acquiring approximately 70,000 net acres and 800 BOE/ D of production in the Bakken play in Montana and North Dakota. Our internal engineers have estimated that total proved reserves from these properties are approximately 21 MMBOE, which are 90 percent oil and 81 percent proved developed producing. The Williston Basin properties currently produce approximately 5 MBOE/ D net, will be 85 percent operated by us and will complement our existing Rockies oil portfolio. In connection with the acquisition, we purchased put contracts on approximately 80 percent of the acquisition s expected production volumes at an average price of $57.50 per Bbl for the remainder of 2007 and all of 2008. The Williston Basin acquisition is expected to close in April 2007.

On January 17, 2007, we announced an intention to form a MLP that will engage in an initial public offering of common units representing limited partner interests. The MLP is expected to own certain Big Horn Basin properties to be acquired from certain subsidiaries of Anadarko and certain of our legacy oil and gas properties. We expect that a registration statement on Form S-1 for the MLP will be filed with the SEC in the second quarter of 2007 with respect to an offering in the range of $175 million to $225 million. Any sale of common units of the MLP would be registered under the Securities Act of 1933, and such common units would only be offered and sold by means of a prospectus. This Report does not constitute an offer to sell or the solicitation of any offer to buy any securities of the MLP, and there will not be any sale of any such securities in any state in which such offer, solicitation, or sale would be unlawful prior to registration or qualification under the securities laws of such state.

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During 2007, we plan to reduce debt by implementing the following initiatives:

- Invest an amount equal to or less than our cash flows from operations;

- Evaluate the potential divestiture of certain Oklahoma natural gas properties; and

- Raise capital through an initial public offering of limited partnership interests in the MLP.

Our debt reduction plans are subject to numerous risks and uncertainties, and there can be no assurance that such plans will be successful.

For 2007, the Board has approved the following $285 million capital budget for oil and natural gas related activities, excluding proved property acquisitions (in thousands):

Development and exploitation	$ 202,000
Exploration	71,000
Acquisitions of leasehold acreage	11,000
Other	1,000
Total	$ 285,000

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 the 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 effect on our results of operations in 2007. In this case, we would have to borrow additional money under our existing revolving credit facility, attempt to access the capital markets, or curtail the capital program. If drilling is curtailed or ended, future cash flows could be materially negatively impacted.

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Results of Operations

Comparison of 2006 to 2005

Below is a comparison of our operations during 2006 with 2005.

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

	Year Ended December 31,			
	2006	2005	*Increase/* (Decrease)	
	(In thousands, except per unit and per day amounts)			
Revenues:				
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%*
Oil marketing revenues	147,563		*147,563*	
Total revenues	$ 640,862	$ 457,324	*$ 183,538*	
Revenues ($/Unit):				
Oil wellhead	$ 54.42	$ 51.06	*$ 3.36*	
Oil hedges	(7.12)	(6.24)	*(0.88)*	
Total oil revenues	$ 47.30	$ 44.82	*$ 2.48*	*6%*
Natural gas wellhead	$ 6.59	$ 7.87	*$ (1.28)*	
Natural gas hedges	(0.35)	(0.78)	*0.43*	
Total natural gas revenues	$ 6.24	$ 7.09	*$ (0.85)*	*(12)%*
Combined wellhead	$ 49.24	$ 49.76	*$ (0.52)*	
Combined hedges	(5.37)	(5.71)	*0.34*	
Total combined oil and natural gas revenues	$ 43.87	$ 44.05	*$ (0.18)*	*0%*
Total production volumes:				

Oil (Bbls)	7,335	6,871	*464*	*7%*
Natural gas (Mcf)	23,456	21,059	*2,397*	*11%*
Combined (BOE)	11,244	10,381	*863*	*8%*
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)	$ 6.99	$ 8.96	*$ (1.97)*	*(22)%*

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Oil revenues increased $39.0 million from $308.0 million in 2005 to $347.0 million in 2006. The increase is 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 is 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 consists 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 in 2005 to $66.22 in 2006. Please read the discussion below regarding the widening of our oil wellhead price to average NYMEX price differential and its related adverse impact on oil revenues for 2006.

Our oil wellhead revenue was reduced by $22.8 million and $20.6 million in 2006 and 2005, respectively, for the 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 is 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 consists 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 in 2005 to $6.99 in 2006.

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.

	Year Ended December 31,	
	2006	**2005**
Oil wellhead ($/Bbl)	$ 54.42	$ 51.06
Average NYMEX ($/Bbl)	$ 66.22	$ 56.56
Differential to NYMEX	$ (11.80)	$ (5.50)
Oil wellhead to NYMEX percentage	82%	90%
Natural gas wellhead ($/Mcf)	$ 6.59	$ 7.87
Average NYMEX ($/Mcf)	$ 6.99	$ 8.96
Differential to NYMEX	$ (0.40)	$ (1.09)
Natural gas wellhead to NYMEX percentage	94%	88%

In the first quarter of 2006, our oil wellhead price as a percentage of the average NYMEX price percentage 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 are 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 have completed maintenance and increased their demand for crude oil, our oil wellhead price as a percentage of the average NYMEX price has improved from the first quarter of 2006, but still

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remains wider than our historical average. We expect that our oil wellhead differentials which averaged $10.06 per Bbl in the fourth quarter of 2006 will improve slightly in the first half of 2007.

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 is due to our natural gas production in the North Louisiana Salt Basin and Crockett County, Texas, which is sold at Katy, Houston Ship Channel, and Henry Hub natural gas prices, which have recently been 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 activities. 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. These purchases are conducted for strategic purposes to assist us in marketing our production by decreasing our dependence on individual markets. These activities allow us to aggregate larger volumes, facilitate our efforts to maximize the prices we receive for production, provide for a greater allocation of future pipeline capacity in the event of curtailments, and enable us to reach other markets.

The following table summarizes our oil marketing activities for 2006 (in thousands, except per BOE amounts):

Oil marketing revenues	$	147,563
Oil marketing expenses		(148,571)
Oil marketing, net	$	(1,008)
Oil marketing revenues per BOE	$	13.12
Oil marketing expenses per BOE		(13.21)
Oil marketing, net per BOE	$	(0.09)

Expenses. On January 1, 2006, we adopted the provisions of SFAS No. 123R, Share-Based Payment (SFAS 123R), which requires that companies 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 granted under our 2000 Incentive Stock Plan (the Plan), which previously was only presented in pro forma disclosures. Total non-cash stock-based compensation expensed in 2006, consisting of expense associated with both restricted stock and stock options, was $9.0 million. This amount is not reported separately on the Consolidated Statements of Operations but is allocated to LOE, exploration, and G&A expense based on the allocation of employee payroll.

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The following table summarizes our expenses 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*	
Oil marketing	148,571		*148,571*	
Derivative fair value (gain) loss	(24,388)	5,290	*(29,678)*	
Loss on early redemption of debt		19,477	*(19,477)*	
Other operating	10,023	9,485	*538*	
Total operating	449,356	266,935	*182,421*	*68%*
Interest	45,131	34,055	*11,076*	
Current and deferred income tax provision	55,406	53,948	*1,458*	
Total expenses	$ 549,893	$ 354,938	*$ 194,955*	*55%*
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 (gain) loss	(2.17)	0.51	*(2.68)*	
Loss on early redemption of debt		1.88	*(1.88)*	
Other operating	0.89	0.91	*(0.02)*	
Total operating	26.74	25.72	*1.02*	*4%*
Interest	4.01	3.28	*0.73*	
Current and deferred 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 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 (defined as oil and natural gas revenues less production expenses) for 2006 decreased seven percent to $30.71 per BOE as compared to $32.94 per BOE for 2005.

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The 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 is due to higher production volumes, which contributed approximately $5.8 million of additional LOE, and an 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 of $2.01 was attributable to:

- increases in prices paid to oilfield service companies and suppliers due to a current higher price environment;
- increased operational activity to maximize production;
- the operation of higher operating cost wells (which have 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 stock-based compensation expense attributable to equity instruments granted to employees under the Plan.

Prior to the adoption of SFAS 123R, non-cash stock-based compensation expense was separately reported on the accompanying Consolidated Statements of Operations. Due to the adoption of SFAS 123R, non-cash stock-based compensation expense in all prior periods presented has been reclassified to allocate the amount to the same respective income statement lines as the employees salary, cash bonus, and benefits. As all full-time employees, including field personnel, are eligible for equity grants under the Plan, LOE, G&A expense, and exploration expense have been changed to reflect the new presentation. This change has 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 stock-based compensation expense allocated to LOE is primarily due to new stock-based compensation awards granted to employees in 2006 and expensing of stock options beginning January 1, 2006 in accordance with SFAS 123R.

The production expense attributable to production, ad valorem, and severance taxes (production taxes) increased $4.2 million from $45.6 million in 2005 to $49.8 million in 2006. The increase is 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. The effect of hedges 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 $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. The higher finding, development, and acquisition costs 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. Of the 14 exploratory dry holes expensed, seven were drilled in the Mid-Continent, six were drilled in the CCA, and one was drilled in the Permian Basin. During 2005, we expensed 47 exploratory dry holes totaling $8.6 million. Of the 47 exploratory dry holes expensed, 45 were drilled in the shallow gas area of Montana, one was drilled in

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the Permian Basin, and one was drilled in the CCA. 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 wrote down the cost of unproved acreage in the shallow gas area of Montana by $4.5 million based on drilling results in the area. The following table details our exploration-related expenses for 2006 and 2005:

	Year Ended December 31,		
	2006	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*

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 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 $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, is primarily the result of increased stock-based compensation expense attributable to equity instruments granted to employees under the Plan.

The previously discussed adoption of SFAS 123R and change in presentation of non-cash stock-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 stock-based compensation expense allocated to G&A expense is primarily due to new stock-based compensation awards granted to employees in 2006 and expensing of stock options beginning January 1, 2006 in accordance with SFAS 123R.

As of December 31, 2006, we had $10.5 million of total unrecognized compensation cost related to unvested, outstanding restricted stock, which is expected to be recognized over a weighted average period of 2.8 years. Additionally, we had $1.2 million of total unrecognized compensation cost related to unvested stock options as of December 31, 2006, which is expected to be recognized over a weighted average period of 1.6 years.

Derivative fair value (gain) loss. To increase clarity in our financial statements by accounting for all contracts under the same method, we elected to discontinue hedge accounting prospectively for all of our remaining commodity derivatives beginning in July 2006. 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 swings in oil and natural gas prices.

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

	Year Ended December 31,		
	2006	2005	*Increase/* (Decrease)
	(In thousands)		
Designated cash flow hedges:			
Ineffectiveness Derivative commodity contracts	$ 1,748	$ 8,371	*$ (6,623)*
Undesignated derivative contracts:			
Mark-to-market loss (gain):			
Interest rate swap		462	*(462)*
Commodity contracts	(17,279)	(2,050)	*(15,229)*
Settlements:			
Interest rate swap		(312)	*312*
Commodity contracts	(8,857)	(1,181)	*(7,676)*
Total derivative fair value (gain) loss	$ (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 $8\frac{3}{8}\%$ Senior Subordinated Notes (the $8\frac{3}{8}\%$ Notes). We redeemed all $150 million of the $8\frac{3}{8}$ Notes with proceeds received from the issuance of our $300 million of 6% Senior Subordinated Notes (the 6% Notes).

Interest expense. Interest expense increased $11.1 million in 2006 as compared to 2005. The increase is primarily due to additional debt used to finance acquisitions and our capital program. We issued $150 million of $7\frac{1}{4}\%$ Senior Subordinated Notes (the $7\frac{1}{4}\%$ Notes) in November 2005, $300 million of 6% Notes in July 2005, and $150 million of $6\frac{1}{4}\%$ Senior Subordinated Notes (the $6\frac{1}{4}\%$ Notes) in April 2004. We also redeemed all $150 million of $8\frac{3}{8}\%$ 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.

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

	Year Ended December 31,		
	2006	2005	*Increase/* (Decrease)
	(In thousands)		
$8\frac{3}{8}\%$ Notes	$	$ 7,852	$ (7,852)
$6\frac{1}{4}\%$ Notes	9,684	9,375	309
6% Notes	18,418	8,437	9,981
$7\frac{1}{4}\%$ Notes	10,984	1,145	9,839
Revolving credit facility	3,609	4,554	(945)
Other	2,436	2,692	(256)
Total	$ 45,131	$ 34,055	$ 11,076

Income taxes. Income tax expense for 2006 increased $1.5 million over 2005. This is 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 are

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fully phased out for 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 recently enacted Texas franchise tax reform measure 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 become current. 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.

Comparison of 2005 to 2004

Below is a comparison of our operations for 2005 with 2004.

Revenues and production. The following table illustrates the primary components of oil and natural gas revenues for 2005 and 2004, as well as each year s respective oil and natural gas volumes:

	Year Ended December 31, 2005	Year Ended December 31, 2004	*Increase/* (Decrease)	
	(In thousands, except per unit and per day amounts)			
Revenues:				
Oil wellhead	$ 350,837	$ 255,394	*$ 95,443*	
Oil hedges	(42,878)	(34,745)	*(8,133)*	
Total oil revenues	$ 307,959	$ 220,649	*$ 87,310*	*40%*
Natural gas wellhead	$ 165,794	$ 81,112	*$ 84,682*	
Natural gas hedges	(16,429)	(3,228)	*(13,201)*	
Total natural gas revenues	$ 149,365	$ 77,884	*$ 71,481*	*92%*
Combined wellhead	$ 516,631	$ 336,506	*$ 180,125*	
Combined hedges	(59,307)	(37,973)	*(21,334)*	
Total combined oil and natural gas revenues	$ 457,324	$ 298,533	*$ 158,791*	*53%*
Revenues ($/Unit):				
Oil wellhead	$ 51.06	$ 38.24	*$ 12.82*	
Oil hedges	(6.24)	(5.20)	*(1.04)*	
Total oil revenues	$ 44.82	$ 33.04	*$ 11.78*	*36%*
Natural gas wellhead	$ 7.87	$ 5.76	*$ 2.11*	
Natural gas hedges	(0.78)	(0.23)	*(0.55)*	
Total natural gas revenues	$ 7.09	$ 5.53	*$ 1.56*	*28%*
Combined wellhead	$ 49.76	$ 37.28	*$ 12.48*	
Combined hedges	(5.71)	(4.21)	*(1.50)*	

Total combined oil and natural gas revenues	$	44.05	$	33.07	*$*	*10.98*	*33%*

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	Year Ended December 31,			
	2005	2004	*Increase/* (Decrease)	
	(In thousands, except per unit and per day amounts)			
Total production volumes:				
Oil (Bbls)	6,871	6,679	*192*	*3%*
Natural gas (Mcf)	21,059	14,089	*6,970*	*49%*
Combined (BOE)	10,381	9,027	*1,354*	*15%*
Daily production volumes:				
Oil (Bbl/ D)	18,826	18,249	*577*	*3%*
Natural gas (Mcf/ D)	57,696	38,493	*19,203*	*50%*
Combined (BOE/ D)	28,442	24,665	*3,777*	*15%*
Average NYMEX prices:				
Oil (per Bbl)	$ 56.56	$ 41.26	*$ 15.30*	*37%*
Natural gas (per Mcf)	$ 8.96	$ 6.11	*$ 2.85*	*47%*

Oil revenues increased $87.3 million from $220.6 million in 2004 to $308.0 million in 2005. The increase is due primarily to higher realized average oil prices, which contributed approximately $80.0 million in additional oil revenues, and an increase in oil production volumes of 192 MBbls, which contributed approximately $7.3 million in additional oil revenues. The $80.0 million increase in oil revenues from higher realized average oil prices consists of an $88.1 million increase resulting from higher average oil wellhead prices, offset by increased hedging payments of $8.1 million, or $1.04 per Bbl. Our average oil wellhead price increased $12.82 per Bbl in 2005 over 2004 as a result of increases in the overall market price for oil, which is reflected in the increase in the average NYMEX price from $41.26 per Bbl in 2004 to $56.56 per Bbl in 2005.

Our oil wellhead revenue was reduced by $20.6 million and $12.3 million in 2005 and 2004, respectively, for the NPI payments related to our CCA properties.

Natural gas revenues increased $71.5 million from $77.9 million in 2004 to $149.4 million in 2005. The increase is due primarily to increased natural gas production volumes of 6,970 MMcf, which contributed approximately $40.1 million in additional natural gas revenues, and higher realized average natural gas prices, which contributed approximately $31.4 million in additional natural gas revenues. The $31.4 million increase in natural gas revenues from higher realized average natural gas prices consists of a $44.6 million increase resulting from higher average natural gas wellhead prices, offset by increased hedging payments of $13.2 million, or $0.55 per Mcf. Our average natural gas wellhead price increased $2.11 per Mcf in 2005 over 2004 due to an increase in the overall market price of natural gas, which is reflected in the increase in the average NYMEX price from $6.11 in 2004 to $8.96 in 2005.

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The table below illustrates the relationship between oil and natural gas wellhead prices as a percentage of average NYMEX prices for the years ended December 31, 2005 and 2004. Management uses the wellhead to NYMEX margin analysis to analyze trends in our oil and natural gas revenues.

	Year Ended December 31,	
	2005	2004
Oil wellhead ($/Bbl)	$ 51.06	$ 38.24
Average NYMEX ($/Bbl)	$ 56.56	$ 41.26
Differential to NYMEX	$ (5.50)	$ (3.02)
Oil wellhead to NYMEX percentage	90%	93%
Natural gas wellhead ($/Mcf)	$ 7.87	$ 5.76
Average NYMEX ($/Mcf)	$ 8.96	$ 6.11
Differential to NYMEX	$ (1.09)	$ (0.35)
Natural gas wellhead to NYMEX percentage	88%	94%

In the fourth quarter of 2005, the oil wellhead to NYMEX price percentage decreased to as low as 88 percent. In the fourth quarter of 2005, the natural gas wellhead to NYMEX price percentage decreased to as low as 75 percent due to pipeline capacity constraints.

Expenses. The following table summarizes our expenses for 2005 and 2004:

	Year Ended December 31,			
	2005	2004	*Increase/* (Decrease)	
Expenses (in thousands):				
Production:				
Lease operations	$ 69,744	$ 47,807	*$ 21,937*	
Production, ad valorem, and severance taxes	45,601	30,313	*15,288*	
Total production expenses	115,345	78,120	*37,225*	*48%*
Other:				
Depletion, depreciation, and amortization	85,627	48,522	*37,105*	
Exploration	14,443	3,935	*10,508*	
General and administrative	17,268	12,059	*5,209*	
Derivative fair value loss	5,290	5,011	*279*	
Loss on early redemption of debt	19,477		*19,477*	
Other operating	9,485	5,028	*4,457*	
Total operating	266,935	152,675	*114,260*	*75%*
Interest	34,055	23,459	*10,596*	
Current and deferred income tax provision	53,948	40,492	*13,456*	
Total expenses	$ 354,938	$ 216,626	$ 138,312	*64%*

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	Year Ended December 31, 2005	Year Ended December 31, 2004	*Increase/ (Decrease)*	
Expenses (per BOE):				
Production:				
Lease operations	$ 6.72	$ 5.30	*$ 1.42*	
Production, ad valorem, and severance taxes	4.39	3.36	*1.03*	
Total production expenses	11.11	8.66	*2.45*	*28%*
Other:				
Depletion, depreciation, and amortization	8.25	5.38	*2.87*	
Exploration	1.39	0.44	*0.95*	
General and administrative	1.67	1.33	*0.34*	
Derivative fair value loss	0.51	0.56	*(0.05)*	
Loss on early redemption of debt	1.88		*1.88*	
Other operating	0.91	0.56	*0.35*	
Total operating	25.72	16.93	*8.79*	*52%*
Interest	3.28	2.60	*0.68*	
Current and deferred income tax provision	5.20	4.49	*0.71*	
Total expenses	$ 34.20	$ 24.02	$ 10.18	*42%*

Production expenses. Total production expenses increased $37.2 million from $78.1 million in 2004 to $115.3 million in 2005 primarily due to an increase in total production volumes, as well as a $2.45 increase in production expenses per BOE. The 28 percent increase in total production expenses per BOE compares to a 33 percent increase in revenues per BOE due to a higher production margin (defined as revenues less production expenses) in 2005 as compared to 2004.

The production expense attributable to LOE for 2005 increased as compared to 2004 by $21.9 million due to an increase in production volumes and an increase in the average per BOE rate. The increase in production volumes was a result of our 2005 drilling program, the 2005 and 2004 acquisitions, and our secondary and tertiary recovery programs, including the waterflood enhancement program and the HPAI program. These increased volumes resulted in approximately $7.2 million of additional LOE. The increase in our average expense per BOE was attributable to increases in prices paid to oilfield service companies and suppliers due to a higher price environment, increased operational activity to maximize production, and the operation of higher operating cost wells, which became more attractive due to increases in oil and natural gas prices. This increased average per BOE rate resulted in approximately $14.8 million of additional LOE for price escalation for services. The previously discussed change in presentation of non-cash stock-based compensation expense resulted in additional LOE of $1.3 million in 2005, or $0.13 per BOE, as compared to $0.7 million in 2004, or $0.07 per BOE. The increase in non-cash stock-based compensation expense allocated to LOE is primarily due to new stock-based compensation awards granted to employees in 2005.

The production expense attributable to production taxes for 2005 increased as compared to 2004 by $15.3 million due to an increase in production volumes and an increase in the average wellhead price we received for oil and natural gas production. The increase in production volumes over 2004 resulted in approximately $4.5 million of additional production taxes. The average wellhead price we received for oil and natural gas revenues increased $12.48 per BOE, resulting in additional production taxes of approximately $10.8 million in 2005. As a percentage of oil and natural gas revenues (excluding the effect of hedges), production taxes for 2005 decreased slightly from 9.0 percent for 2004 to 8.8 percent for 2005. The effect of hedges 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.

DD&A expense. DD&A expense increased $37.1 million from $48.5 million in 2004 to $85.6 million in 2005 due to a higher per BOE rate and increased production volumes. The per BOE rate in 2005 increased $2.87 as compared to 2004 due to the development of proved undeveloped reserves from the 2004 acquisitions, which do not increase total proved reserves, and higher drilling costs per BOE of reserves than our historical DD&A rate in certain areas. These factors resulted in additional DD&A expense of $29.8 million. The increase in production volumes of 1,354 MBOE over 2004 resulted in $7.3 million of additional DD&A expense.

Exploration expense. Exploration expense increased $10.5 million in 2005 as compared to 2004. During 2005, we expensed 47 exploratory dry holes totaling $8.6 million. Of the 47 exploratory dry holes expensed, 45 were drilled in the shallow gas area of Montana, one was drilled in the Permian Basin, and one was drilled in the CCA. In 2004, we expensed four exploratory dry holes at a cost of $2.0 million. In 2004, three of the exploratory dry holes were drilled in our Montana shallow gas area and one was drilled in the Barnett Shale in our Mid-Continent area. The following table details our exploration-related expenses:

	Year Ended December 31,		
	2005	**2004**	***Increase/* (Decrease)**
	(In thousands)		
Dry holes	$ 8,632	$ 2,050	*$ 6,582*
Geological and seismic	3,137	1,006	*2,131*
Delay rentals	635	204	*431*
Impairment of unproved acreage	2,039	675	*1,364*
Total	$ 14,443	$ 3,935	*$ 10,508*

G&A expense. G&A expense increased $5.2 million from $12.1 million in 2004 to $17.3 million in 2005. The overall increase, as well as the $0.34 increase in the per BOE rate, is a result of 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.

The previously discussed change in presentation of non-cash stock-based compensation expense resulted in additional G&A expense of $2.6 million in 2005, or $0.25 per BOE, as compared to $1.1 million in 2004, or $0.12 per BOE. The increase in non-cash stock-based compensation expense allocated to G&A expense is primarily due to new stock-based compensation awards granted to employees in 2005.

Derivative fair value loss. During 2005, we recorded a $5.3 million derivative fair value loss as compared to $5.0 million in 2004. This derivative fair value loss represents the ineffective portion of the mark-to-market loss on our derivative hedging instruments, settlements received on fixed-to-floating interest rate swaps, losses (gains) related to commodity derivatives not designated as hedges, and changes

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in the mark-to-market value of fixed-to-floating interest rate swaps. The components of the derivative fair value loss reported in 2005 and 2004 are as follows:

	Year Ended December 31, 2005	Year Ended December 31, 2004	*Increase/* (Decrease)
		(In thousands)	
Designated cash flow hedges:			
Ineffectiveness Commodity contracts	$ 8,371	$ 5,018	*$ 3,353*
Undesignated derivative contracts:			
Mark-to-market loss Interest rate swap	150	272	*(122)*
Mark-to-market gain Commodity contracts	(3,231)	(279)	*(2,952)*
Total derivative fair value loss	$ 5,290	$ 5,011	*$ 279*

Ineffectiveness loss related to our derivative commodity contracts designated as hedges increased $3.4 million in 2005 as compared to 2004 due primarily to an increase in oil wellhead differentials on our production in the CCA. The interest rate swap loss in 2005 decreased as compared to 2004 due to the expiration of our fixed-to-floating interest rate swap in June 2005. The ineffectiveness loss is offset by a $3.2 million gain related to undesignated commodity contracts, which increased due to changes in the fair value of certain natural gas basis swaps.

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 write-off of unamortized debt issuance costs of our $8^3/8$% Notes. We redeemed all $150 million of the $8^3/8$% Notes with proceeds received from the issuance of our $300 million 6% Notes in July 2005.

Other operating expense. Other operating expense increased $4.5 million from $5.0 million in 2004 to $9.5 million in 2005. This increase is mainly due to an increase in natural gas transportation costs attributable to higher production volumes for 2005 as compared to 2004.

Interest expense. Interest expense increased $10.6 million in 2005 as compared to 2004. The increase is primarily due to additional debt used to finance acquisitions and our capital program. We issued $150 million of $7^1/4$% Notes in November 2005, $300 million of 6% Notes in July 2005, and $150 million of $6^1/4$% Notes in April 2004. We also redeemed $150 million of $8^3/8$% Notes in August 2005. The weighted average interest rate, net of hedges, for 2005 was 6.8 percent as compared to 7.7 percent for 2004. This lower weighted average interest rate is the result of the debt issuances which have rates lower than our historical average rate.

The following table illustrates the components of interest expense for 2005 and 2004:

	Year Ended December 31, 2005	Year Ended December 31, 2004	*Increase/* (Decrease)
		(In thousands)	
$8^3/8$% Notes	$ 7,852	$ 12,563	*$ (4,711)*
$6^1/4$% Notes	9,375	7,005	*2,370*
6% Notes	8,437		*8,437*
$7^1/4$% Notes	1,145		*1,145*

Revolving credit facility	4,554	1,565	*2,989*
Other	2,692	2,326	*366*
Total	$ 34,055	$ 23,459	*$ 10,596*

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Income taxes. Income tax expense for 2005 increased $13.5 million from 2004. This increase is due primarily to an increase of $34.7 million in income before income taxes. Our effective tax rate increased slightly in 2005 to 34.3 percent from 33.0 percent in 2004.

Capital Resources

Our primary capital resources are as follows:

- Cash flows from operating activities;
- Cash flows from financing activities; and
- Current capitalization.

Cash flows from operating activities. 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 oil marketing expenses) in 2006 from 2005, which resulted in a $5.1 million increase in cash provided by operating activities.

For 2005 as compared to 2004, cash provided by operating activities increased $120.5 million from $171.8 million in 2004 to $292.3 million in 2005. This increase resulted mainly from an increase in revenues which outpaced the increase in total operating expenses. Revenues increased in 2005 as both production volumes and commodity prices were higher than in 2004. Our production volumes increased 1,354 MBOE from 9,027 MBOE in 2004 to 10,381 MBOE in 2005. Our average realized oil price increased $11.78 per Bbl from $33.04 per Bbl in 2004 to $44.82 in 2005. Our average realized natural gas price increased $1.56 per Mcf from $5.53 in 2004 to $7.09 per Mcf in 2005. Total operating expenses increased $114.3 million from $152.7 million in 2004 to $266.9 million in 2005.

Cash flows from investing activities. 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, 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.

For 2005 as compared to 2004, cash used in operating activities increased $140.1 million from $433.5 million in 2004 to $573.6 million in 2005. This increase was primarily due to a $135.4 million increase in costs incurred for the development of oil and natural gas properties. In 2004, we purchased all of the outstanding capital stock of Cortez, a privately held, independent oil and natural gas company, for a total purchase price of $127.0 million.

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 common stock. 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 4.0 million shares of our common stock. The net proceeds, after underwriting discounts and commissions and other expenses, were used to repay outstanding balances under our revolving credit facility, invest in oil and natural gas activities, and to pay general corporate expenses.

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. Our total borrowings less repayments on our revolving credit facility, as described above,

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resulted in a net decrease in outstanding borrowings under our revolving credit facility of $12 million from $80 million at December 31, 2005 to $68 million at December 31, 2006.

During 2005, we received net cash of $281.8 million from financing activities. In July 2005, we issued $300 million of 6% Notes and received net proceeds of approximately $294.5 million. In November 2005, we issued $150 million of 7 1/4% Notes and received net proceeds of approximately $148.5 million. We used approximately $165.9 million of the net proceeds to (i) redeem all of our outstanding 8 3/8% Notes, (ii) pay the related early redemption premiums, and (iii) reduce outstanding borrowings under our revolving credit facility.

During 2004, we received net cash of $262.3 million from financing activities. On April 2, 2004, we issued $150 million of 6 1/4% Notes and received net proceeds of approximately $146.4 million. On June 10, 2004, we sold 3.0 million shares of our common stock to the public at a price of $17.97 per share. The net proceeds of the common stock offering, after underwriting discounts and commissions and other expenses, were approximately $52.9 million. We used the net proceeds of the debt issuance and common stock offering to fund the 2004 acquisition of Cortez, repay indebtedness under our revolving credit facility, and for general corporate purposes.

Current capitalization. At December 31, 2006, we had total assets of $2.0 billion. Total capitalization as of December 31, 2006 was $1.5 billion, of which 55 percent was represented by stockholders equity and 45 percent by long-term debt. At December 31, 2005, we had total assets of $1.7 billion. Total capitalization as of December 31, 2005 was $1.2 billion, of which 45 percent was represented by stockholders equity and 55 percent by long-term debt. The percentages of our capitalization represented by stockholders equity and long-term debt could vary in the future if debt is used to finance future capital projects or potential acquisitions.

Capital Commitments

Our primary needs for cash are as follows:

- Development, exploitation, and exploration of our existing oil and natural gas properties;
- Acquisitions of oil and natural gas properties and leasehold acreage;
- Other general property and equipment;
- Funding of necessary working capital; and
- Payment of contractual obligations.

Development, exploitation, and exploration of existing properties. The following table summarizes our costs incurred (excluding asset retirement obligations) related to development, exploitation, and exploration activities during 2006, 2005, and 2004:

	Year Ended December 31,		
	2006	**2005**	**2004**
		(In thousands)	
Development and exploitation	$ 228,014	$ 236,467	$ 117,464
Exploration	95,205	57,046	30,546
HPAI	25,470	32,053	39,628
Total	$ 348,689	$ 325,566	$ 187,638

Development and exploitation. 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 2006 included a total of 182 gross (72.3 net) successful wells and 4 gross (2.5 net) developmental dry holes.

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We currently have 13 operated rigs drilling on the onshore continental United States with 3 rigs in the CCA, 2 rigs in Oklahoma, 1 rig in North Texas, and 7 rigs in West Texas.

Exploration. Our expenditures for exploration investments primarily relate to drilling exploratory wells, seismic costs, delay rentals, and geological and geophysical costs. During 2006, our exploration capital was invested primarily in drilling extension wells in the Mid-Continent area. In 2006, our exploration capital yielded 71 gross (19.3 net) successful wells and 14 gross (7.6 net) exploratory dry holes.

HPAI programs. During 2006, 2005, and 2004, the Company invested $25.5 million, $32.1 million, and $39.6 million on implementation of the HPAI programs in the Pennel, Coral Creek, and Little Beaver units of the CCA.

Acquisitions of proved property and leasehold acreage. The following table summarizes our costs incurred (excluding asset retirement obligations) for oil and natural gas property acquisitions during 2006, 2005, and 2004:

	Year Ended December 31,		
	2006	**2005**	**2004**
		(In thousands)	
Acquisitions of proved property	$ 4,486	$ 224,469	$ 204,907
Acquisitions of leasehold acreage	24,462	21,205	33,926
Total	$ 28,948	$ 245,674	$ 238,833

2006 Acquisitions. We invested $4.5 million during 2006 in additional working interests spread over our various core areas.

2005 Acquisitions. 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 are located primarily in the western Anadarko Basin and the Golden Trend area of Oklahoma. On November 30, 2005, we acquired oil and natural gas properties from Kerr-McGee Corporation for a purchase price of approximately $101.4 million. The acquired properties are located in the Levelland-Slaughter, Howard Glasscock, Nolley-McFarland, and Hutex fields in west Texas and the Oakdale, Calumet, and Rush Springs fields in western Oklahoma. On September 8, 2005, we acquired 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.

2004 Acquisitions. On April 14, 2004, we completed the acquisition of Cortez for a purchase price of approximately $127.0 million. The acquired properties are located in the CCA of Montana, the Permian Basin of west Texas and southeastern New Mexico, and in the Mid-Continent area. On June 17, 2004, we completed the acquisition of natural gas producing properties and undeveloped leases in the Overton Field located in Smith County, Texas for $83.1 million.

Leasehold acreage costs. Our capital expenditures for leasehold acreage costs during 2006, 2005, and 2004 totaled $24.5 million, $21.2 million, and $33.9 million, respectively. 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. Leasehold costs incurred in 2004 relate primarily to the Cortez, Overton, and Montana shallow gas acreage acquisitions. Of the $33.9 million of capital expenditures for unproved property in 2004, $3.0 million and $18.4 million relate to the Cortez and Overton acquisitions, respectively, $7.9 million relates to leases acquired in our Montana shallow gas area, and the remaining $4.6 million relates to the acquisition of unproved acreage in various areas.

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Other general property and equipment. Our capital expenditures for other general property and equipment during 2006, 2005, and 2004 totaled $4.3 million, $6.8 million, and $7.6 million, respectively. Capital expenditures for other general property and equipment include aircraft, corporate leasehold improvements, computers, and various field equipment.

Funding of necessary working capital. At December 31, 2006, our working capital (defined as total current assets less total current liabilities) was negative $40.7 million while at December 31, 2005, our working capital was negative $56.8 million, an improvement of $16.1 million. At December 31, 2004, our working capital was negative $15.6 million. The improvement in 2006 is primarily attributable to decreases in the NYMEX price of natural gas, which favorably impacted the fair value of outstanding derivative contracts, net of deferred taxes, offset by the decrease in accounts receivable from sales of natural gas resulting from the lower price. The deterioration in 2005 was primarily attributable to changes in the fair value of outstanding derivative contracts, net of the deferred tax effect of marking these contracts to market.

For 2007, we expect working capital to remain negative. Negative working capital is expected mainly due to fair values of our derivative contracts, the settlements of which will be offset by cash flows from the hedged production, and deferred hedge 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. The overall 2007 commodity prices and our related differentials for oil and natural gas will be the largest variables affecting working capital. Our operating cash flow is determined in large part by commodity prices. Assuming moderate to high commodity prices, our operating cash flow should remain positive in 2007.

The Board has approved a capital budget of approximately $285 million for 2007. 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, cash on hand, and borrowings under our existing revolving credit agreement.

Contractual obligations. The following table illustrates our contractual obligations and commercial commitments outstanding at December 31, 2006:

	Payments Due by Period				
Contractual Obligations and Commitments	**Total**	**2007**	**2008-2009**	**2010-2011**	**Thereafter**
			(In thousands)		
6 1/4% Notes(a)	$ 220,313	$ 9,375	$ 18,750	$ 18,750	$ 173,438
6% Notes(a)	462,000	18,000	36,000	36,000	372,000
7 1/4% Notes(a)	269,625	10,875	21,750	21,750	215,250
Revolving credit facility(a)	80,212	3,053	6,106	71,053	
Derivative obligations(b)	77,524	53,804	22,880	840	
Development commitments(c)	199,092	135,779	62,942	371	
Operating leases(d)	14,218	1,818	4,304	4,199	3,897
Asset retirement obligations(e)	134,103	636	1,273	1,273	130,921
Total	$ 1,457,087	$ 233,340	$ 174,005	$ 154,236	$ 895,506

(a) Amounts included in the table above 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.

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(b) Derivative obligations represent net liabilities for derivatives that were valued as of December 31, 2006. With the exception of $54.7 million of deferred premiums on derivative contracts, the ultimate settlement amounts of the remaining portions of our 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 $46.7 million which is accrued at December 31, 2006, future minimum payments for electricity, seismic data analysis, and drilling rig operations of $140.4 million, and $12.0 million for minimum capital obligations associated with the remaining commitment wells to be drilled under the ExxonMobil joint development agreement. Also at December 31, 2006, we had $132.3 million of authorized purchases not placed to vendors (authorized AFEs), which were not accrued and are excluded from the above table but are budgeted for and expected to be made unless circumstances change.

(d) Operating leases represent office space and equipment obligations that have non-cancelable lease terms in excess of one year. 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 AROs.

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. Recently, alternative transportation routes and markets have been developed by moving a portion of the crude oil production through Enbridge 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 Platte Pipeline to Wood River, Illinois as well as other pipelines connected to the Guernsey, Wyoming area. While shipments on Platte Pipeline are currently oversubscribed and subject to apportionment since December 2005, we were allocated transportation 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 slightly improve in the first half of 2007 as compared to the fourth quarter of 2006. 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. We cannot accurately predict crude oil differentials. Natural gas differentials are expected to remain approximately constant in the first half of 2007 as compared to the fourth quarter of 2006. 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.

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Letters of credit. As of December 31, 2006, we had \$21.1 million of outstanding letters of credit, \$20.0 million of which relates to the ExxonMobil joint development agreement. As of February 20, 2007, we had \$20.0 million of outstanding letters of credit, all of which relates to the ExxonMobil joint development agreement.

In prior years, we have had letters of credit with some of our commodity derivative contract counterparties. At any point in time, we had hedge margin deposits and letters of credit equal to the amount by which the current mark-to-market liability of our commodity derivative contracts exceeded the margin maintenance thresholds we have negotiated with our counterparties. Once a margin threshold was reached, we were required to maintain cash reserves in an account with the counterparty or post letters of credit in lieu of cash to ensure future settlement were made pursuant to our contracts. These funds were released back to us as our mark-to-market liability decreases due to either a drop in the futures prices of oil and natural gas or the passage of time as settlements are made. During the third quarter of 2006, we negotiated with these counterparties to remove the letter of credit requirements as long as our senior subordinated notes maintain their current rating.

Liquidity

Cash on hand, internally generated cash flows, and the borrowing capacity under our revolving credit facility are our major sources of liquidity. 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 any major acquisitions we might secure in the future and to maintain our financial flexibility. Because of rig and lease commitments, the Company expects its capital expenditures to exceed operating cash flows in the first and second quarters of 2007, but to be below cash flows from operations in the third and fourth quarters of 2007.

Internally generated cash flows. Our internally generated cash flows, results of operations, and financing for our operations are dependent on oil and natural gas prices. Realized oil and natural gas prices for 2006 remained constant as compared to 2005. These prices have historically fluctuated widely in response to changing market forces. For 2006, approximately 65 percent of our production was oil. As we previously discussed, our oil wellhead differentials during 2006 increased significantly from 2005, adversely impacting the amount of oil revenues we received on our oil production. To the extent oil and natural gas prices decline or we continue to experience significantly increased 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 facility. Our principal source of short-term liquidity is our revolving credit facility, which matures on December 29, 2010. The revolving credit facility is with a bank syndicate comprised of Bank of America, N.A. and other lenders. The borrowing base is determined semi-annually and may be increased or decreased, up to a maximum of \$750 million. The borrowing base as of December 31, 2006 was \$550 million.

Our obligations under the revolving credit facility are guaranteed by our restricted subsidiaries and secured by a first priority-lien on substantially all of our proved oil and natural gas reserves and a pledge of the capital stock and equity interests of our restricted subsidiaries.

Amounts outstanding under the revolving credit facility are subject to varying rates of interest based on (i) the amount outstanding under the revolving credit facility in relation to the borrowing base and

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(ii) whether the loan is a Eurodollar loan or a Base Rate loan. The following table summarizes the calculation of the various interest rates for both Eurodollar and Base Rate loans:

Ratio of Total Outstandings to Borrowing Base	Eurodollar Loans(a)	Base Rate Loans(b)
Less than .40 to 1	LIBOR + 1.000%	Base Rate + 0.000%
From .40 to 1 but less than .75 to 1	LIBOR + 1.250%	Base Rate + 0.000%
From .75 to 1 but less than .90 to 1	LIBOR + 1.500%	Base Rate + 0.250%
.90 to 1 or greater	LIBOR + 1.750%	Base Rate + 0.500%

(a) The LIBOR rate is equal to the rate determined by Bank of America, N.A. to be the average British Bankers Association Interest Settlement Rate for deposits in dollars for a similar interest period (either one, two, three, or six months, or such other period that is twelve months or less as selected by us and consented to by each lender).

(b) 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.

The borrowing base is redetermined each April 1 and October 1. The bank syndicate has the ability to request one additional borrowing base redetermination per year, and we are permitted to request two additional borrowing base redeterminations per year. Generally, if amounts outstanding ever exceed the borrowing base, we must reduce the amounts outstanding to the redetermined borrowing base within six months, provided that if amounts outstanding exceed the borrowing base as a result of any sale of our assets or permitted subordinated debt, we must reduce the amounts outstanding immediately upon consummation of the sale.

Borrowings under the revolving credit facility may be repaid at anytime without penalty.

Our revolving credit facility contains financial and other restrictive covenants that limit our ability to engage in activities that may be in our long-term best interests. Our ability to borrow under our revolving credit facility is subject to financial covenants consisting of a current ratio and an interest coverage ratio. Our revolving credit facility limits our ability to effect mergers, asset sales, and change of control events. These covenants also contain restrictions regarding our ability to incur additional indebtedness in the future.

On December 31, 2006, we had $68 million outstanding under the revolving credit facility. On February 20, 2007, we had $211 million outstanding under the revolving credit facility.

In connection with our proposed acquisitions from Anadarko, we expect to enter into a new $1.25 billion five-year revolving credit facility in March 2007 with an initial borrowing base of $650 million that will increase to $950 million upon completion of the Williston Basin acquisition, which is scheduled to close in April 2007. We also expect that one of our subsidiaries will enter into a $300 million five-year revolving credit facility in March 2007 with a $115 million borrowing base and a $10 million overadvance feature, which will be non-recourse to us.

Indentures governing our senior subordinated notes. We and our restricted subsidiaries are subject to certain negative and financial covenants under the indentures governing our 6$^{1}/_{4}$% Notes, our 6% Notes, and our 7$^{1}/_{4}$% Notes due 2017 (collectively, the Notes). The provisions of the indentures limit our and our restricted subsidiaries ability to, among other things:

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

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- incur liens;
- create any consensual limitation on the ability of our restricted subsidiaries to pay dividends, make loans or transfer property to us;
- engage in transactions with our affiliates;
- sell assets, including capital stock of our subsidiaries; and
- consolidate, merge or transfer assets.

During any period that the Notes have investment grade ratings from both Moody s Investors Service, Inc. and Standard and Poor s Ratings Services and no default has occurred and is continuing, the foregoing covenants will cease to be in effect with the exception of covenants that contain limitations on liens and on, among other things, certain consolidations, mergers and transfers of assets.

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

Off-Balance Sheet Arrangements

We do not have any off-balance sheet arrangements that are material to our financial position or results of operations.

Inflation and Changes in Prices

Our revenues, the value of our assets, and our ability to obtain bank loans or additional capital on attractive terms have been and will continue to be affected by changes in oil and natural gas prices. Historically, significant fluctuations have occurred in oil and natural gas prices. The following table indicates the average oil and natural gas prices received for 2006, 2005, and 2004. Average equivalent prices for 2006, 2005, and 2004 were decreased by $5.37, $5.71, and $4.21 per BOE, respectively, as a result of our hedging activities. Average prices per BOE indicate the composite impact of changes in oil and natural gas prices.

	Year Ended December 31,		
	2006	2005	2004
Net Price Realization with Hedges:			
Oil ($/Bbl)	$ 47.30	$ 44.82	$ 33.04
Natural gas ($/Mcf)	6.24	7.09	5.53
Combined ($/BOE)	43.87	44.05	33.07
Average Wellhead Price:			
Oil ($/Bbl)	$ 54.42	$ 51.06	$ 38.24
Natural gas ($/Mcf)	6.59	7.87	5.76
Combined ($/BOE)	49.24	49.76	37.28

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

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Critical Accounting Policies and Estimates

The preparation of financial statements in accordance with U.S. generally accepted accounting principles requires management to make estimates and assumptions that affect reported amounts and related disclosures. Management considers an accounting estimate to be critical if it requires assumptions to be made that were uncertain at the time the estimate was made, and changes in the estimate or different estimates that could have been selected could have a material impact on Encore s consolidated results of operations or financial condition. Management has identified the following critical accounting policies and estimates.

Oil and Natural Gas Properties

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

If an exploratory well does not find reserves or does not find reserves in a sufficient quantity as to make them economically producible, the previously capitalized costs are expensed in our Consolidated Statements of Operations and shown as a non-cash adjustment to net income in the Operating activities section of our Consolidated Statements of Cash Flows in the period in which the determination was made. If a determination cannot be made within one year of the exploration well being drilled and no other drilling or exploration activities to evaluate the discovery are firmly planned, all previously capitalized costs associated with the exploratory well are expensed and shown as a non-cash adjustment to net income at that time. Thus, we might expense the costs of a given well if firm plans do not exist after one year, but later complete the well as a producing property. This could occur as the expected rate of return to complete a marginal well often is less than other projects. Should this occur, we do not reverse the previously expensed costs. Re-drilling or directional drilling in a previously abandoned well is classified as development or exploratory based on whether it is in a proved or unproved reservoir. Expenditures for repairs and maintenance to sustain or increase production from the existing producing reservoir are charged to expense as incurred. Expenditures to recomplete a current well in a different unproved reservoir are capitalized pending determination that economic reserves have been added. If the recompletion is not successful, the expenditures are charged to expense. All capitalized costs associated with both development and exploratory wells are shown as Development of oil and natural gas properties in the Investing activities section of our Consolidated Statements of Cash Flows.

DD&A expense is directly affected by our reserve estimates. Any change in reserves directly impacts the amount of DD&A expense that we recognize in a given period. Assuming no other changes, such as an increase in depreciable base, as our reserves increase, the amount of DD&A expense in a given period decreases and vice versa. Changes in future commodity prices would likely result in increases or decreases in estimated recoverable reserves. DD&A expense associated with lease and well equipment and intangible drilling costs are based upon only proved developed reserves, while DD&A expense for capitalized leasehold costs is based upon total proved reserves. As a result, changes in the classification of our reserves could have a material impact on our DD&A expense. Additionally, Miller & Lents, our independent reserve engineers, estimate our reserves once a year at December 31. As a result, quarterly reported DD&A expense is based on internally prepared estimates of reserves additions and reclassifications to the December 31 amounts prepared by Miller & Lents.

Significant tangible equipment added or replaced is capitalized. Expenditures to construct facilities or increase the productive capacity from existing reserves are capitalized. Internal costs directly associated with the development of proved properties are capitalized as a cost of the property and are classified accordingly in our consolidated financial statements. Capitalized costs are amortized on a unit-of-production basis over the remaining life of total proved developed reserves or proved reserves, as applicable. Natural gas volumes are converted to equivalent barrels of oil at the rate of six Mcf to one Bbl of oil. Significant revisions to reserve estimates can be and are made by our reserve engineers each year. Mostly these are the result of changes in price, but as reserve quantities are estimates, they can also change as more or better information is collected, especially in the case of estimates in newer fields. Downward revisions have the effect of increasing our DD&A rate, while upward revisions have the effect of decreasing our DD&A rate.

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

The annual estimate of reserves by Miller & Lents results in a new DD&A rate which we use for the preceding fourth quarter after adjusting for fourth quarter production. We internally estimates reserve additions and reclassifications of reserves from proved undeveloped to proved developed for use in determining a DD&A rate at the end of the first, second, and third quarters. These internal estimates are based on expected results from the capital projects completed during the quarter, adjusted for any clear deviations from expectations. These estimated results may differ from the reserve additions and reclassifications estimated by Miller & Lents at the end of the year. However, we feel that by estimating the results of capital projects throughout the year, our quarterly DD&A rate is more accurate.

In accordance with SFAS No. 144, Accounting for the Impairment or Disposal of Long-Lived Assets , we are required to assess the need for an impairment of capitalized costs of long-lived assets to be held and used, including proved oil and natural gas properties, whenever events and circumstances indicate that the carrying value of the asset may not be recoverable. If impairment is indicated based on a comparison of the asset s carrying value to its undiscounted expected future net cash flows, then it is recognized to the extent that the carrying value exceeds fair value. Expected future net cash flows are based on existing proved reserve and production information and pricing assumptions that management believes are reasonable. Any impairment charge incurred is expensed and reduces our recorded basis in the asset pool. Management aggregates proved property for impairment testing the same way as for calculating DD&A. The price assumptions used to calculate undiscounted cash flows is based on judgment. We use prices consistent with the prices used in bidding on acquisitions and/or assessing capital projects. These price assumptions are critical to the impairment analysis as lower prices could trigger impairment while higher prices would have the opposite effect.

Unproved properties, the majority of the costs of which relates to the acquisition of leasehold interests, are assessed for impairment on a property-by-property basis for individually significant balances and on an aggregate basis for individually insignificant balances. If the assessment indicates an impairment, a loss is recognized by providing a valuation allowance at the level consistent with the level at which impairment was assessed. The impairment assessment is affected by economic factors such as the results of exploration activities, commodity price outlooks, remaining lease terms, and potential shifts in business strategy employed by management. In the case of individually insignificant balances, the amount of the impairment loss recognized is determined by amortizing the portion of these properties costs which we feel will not be transferred to proved over the life of the lease. One of the primary factors in determining what portion will not be transferred to proved is the relative proportion of such properties on which proved reserves have been found in the past. Since the wells drilled on unproved acreage are inherently exploratory in nature, actual results could vary from estimates especially in newer areas in which we do not have a long history of drilling. Unproved properties had a net book value of $47.5 million and $37.6 million as of December 31, 2006 and 2005, respectively. We recorded charges for unproved acreage impairment in the amounts of $10.9 million, $2.0 million, and $0.7 million in 2006, 2005, and 2004, respectively.

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Oil and natural gas reserves. Assumptions used by the independent reserve engineers in calculating reserves or regarding the future cash flows or fair value of our properties are subject to change in the future. The accuracy of reserve estimates is a function of: (i) the quality and quantity of available data; (ii) the interpretation of that data; (iii) the accuracy of various mandated economic assumptions; and (iv) the judgment of the independent reserve engineer. Future prices received for production and future production costs may vary, perhaps significantly, from the prices and costs assumed for purposes of calculating reserve estimates. We may not be able to develop proved reserves within the periods estimated. Furthermore, prices and costs will not remain constant. Actual production may not equal the estimated amounts used in the preparation of reserve projections. As these estimates change, the amount of calculated reserves change. Any change in reserves directly impacts our estimate of future cash flows from the property, the property s fair value, and our depletion rate.

Asset retirement obligations. We are required to estimate our eventual obligations associated with the retirement of tangible long-lived assets that result from the acquisition, construction, and development of our oil and natural gas wells and related facilities. We recognize the fair value of a liability for an ARO in the period in which the liability is incurred. The ARO is capitalized as part of the carrying amount of our oil and natural gas properties at its discounted fair value. The liability is then accreted each period until it is settled or the well is sold, at which time the liability is reversed.

The fair value of the liability associated with the ARO is determined using significant assumptions, including current estimates of the plugging and abandonment costs, annual inflation of these costs, the productive life of the asset and our risk-adjusted costs to settle such obligations discounted using our risk-adjusted interest rate, which is calculated based on comparisons of our current borrowing rate to U.S. Treasury rates of a similar maturity. Changes in any of these assumptions can result in significant revisions to the estimated ARO. Revisions to the obligation are recorded with an offsetting change to the carrying amount of the related oil and natural gas properties asset, resulting in prospective changes to DD&A expense and accretion of the liability. Because of the subjectivity of assumptions and the relatively long life of most of our oil and natural gas assets, the costs to ultimately retire these assets may vary significantly from previous estimates.

Goodwill

Goodwill represents the excess of the purchase price over the estimated fair value of the net assets acquired in the purchases of Cortez in April 2004 and of Crusader in October 2005. See Note 3 of Notes to Consolidated Financial Statements included in Item 8. Financial Statements and Supplementary Data for additional information regarding these acquisitions. We test goodwill for impairment on an annual basis or whenever indicators of impairment exist. We performed our annual impairment test at December 31, 2006, and determined that no impairment existed. If impairment is determined to exist, we will measure our impairment based on a comparison of the carrying value of goodwill to the implied fair value of the goodwill. We would recognize an impairment charge for any amount by which the carrying value of goodwill exceeds its fair value. The goodwill test is performed at the reporting unit level. We have determined that we have only one reporting unit, which is oil and natural gas production in the United States.

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

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Net Profits Interests

A major portion of our acreage position in the CCA is subject to NPI ranging from one percent to 50 percent. The holders of these NPIs are entitled to receive a fixed percentage of the cash flow remaining after specified costs have been deducted 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 drilling costs. The amounts of reserves and production calculated to be attributable to these NPIs are deducted from our reserves and production data, and our revenues are reported net of NPI payments. The reserves and production that are attributed to the NPIs are calculated by dividing estimated future NPI payments (in the case of reserves) or prior period actual NPI payments (in the case of production) by the commodity prices current at the determination date. Fluctuations in commodity prices and the levels of development activities in the CCA from period to period will impact the reserves and production attributed to the NPIs and will have an inverse effect on our reported reserves and production. Based largely on a continued increase in commodity prices and production volumes, we expect to make higher NPI payments in 2007 and possibly beyond than we have in previous years, which directly impacts our oil and natural gas revenues, production, reserves, and net income.

Revenue Recognition

Revenues are recognized for our share of jointly owned properties as oil and natural gas is produced and sold, net of royalties and NPI payments. Natural gas revenues are also reduced by any processing and other fees paid except for transportation costs paid to third parties, which are recorded as expense. Natural gas revenue is recorded using the sales method of accounting whereby revenue is recognized as natural gas is sold rather than as it is produced. Royalties, NPIs, and severance taxes are paid based upon the actual price received from the sales. To the extent actual quantities and values of oil and natural gas are unavailable for a given reporting period because of timing or information not received from third parties, we estimate and record the expected sales volumes and price for those properties. If our underproduced imbalance position (i.e., we have cumulatively been over-allocated production) is greater than our share of remaining reserves, we record a liability for the excess at year-end prices. We also do not recognize revenue for the production in tanks, oil marketed on behalf of third parties, or oil purchased in pipelines that has not been delivered to the purchaser yet. Our net oil inventories in pipelines were 146,284 Bbls and 49,543 Bbls at December 31, 2006 and 2005, respectively. Natural gas imbalances at December 31, 2006 and December 31, 2005, were 188,757 MMBTU under-delivered to us and 204,400 MMBTU over-delivered to us, respectively.

Income Taxes

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

Hedging and Related Activities

During July 2006, we elected to discontinue hedge accounting prospectively for all of our commodity derivatives which were previously accounted for as hedges. While this change will have no effect on our cash flows, future results of operations will be affected by mark-to-market gains and losses, which fluctuate with the swings in oil and natural gas prices. As of July 2006, all of our remaining derivative contracts accounted for as hedges were dedesignated. At the point of dedesignation, the gain (loss) to be amortized to revenue was established and is deferred in Accumulated Other Comprehensive Loss (AOCL). We are recognizing prospective mark-to-market gains and losses in earnings rather than deferring such amounts in AOCL.

New Accounting Pronouncements

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

In September 2006, the FASB issued SFAS 157. SFAS 157 clarifies the principle that fair value should be based on the assumptions market participants would use when pricing an asset or liability and establishes a fair value hierarchy that prioritizes the information used to develop those assumptions. Under SFAS 157, fair value measurements would be separately disclosed by level within the fair value hierarchy. SFAS 157 is effective for financial statements issued for fiscal years beginning after November 15, 2007, and interim periods within those fiscal years. Encore has not yet determined the impact, if any, that the implementation of SFAS 157 will have on its results of operations or financial condition.

FASB Interpretation No. 48, Accounting for Uncertainty in Income Taxes (FIN 48)

In June 2006, the FASB issued FIN 48. FIN 48 clarifies the accounting for uncertainty in income taxes recognized in a company s financial statements in accordance with SFAS No. 109, *Accounting for Income Taxes* . FIN 48 prescribes a recognition threshold and measurement attribute for the financial statement recognition and measurement of a tax position taken or expected to be taken in a tax return. FIN 48 is effective for fiscal years beginning after December 15, 2006 and is not expected to have a material impact on our financial condition, results of operations, or cash flows.

Information Concerning Forward-Looking Statements

This Report contains forward-looking statements, which give our current expectations or forecasts of future events. You can identify our forward-looking statements by the fact that they do not relate strictly to historical or current facts. These statements may include words such as anticipate , estimate , expect , project , intend , plan , should , and other words and terms of similar meaning. In particular, forward-looking statements included in this Report relate to, among other things, the following:

expected capital expenditures and the focus of our capital program;

areas of future growth;

our drilling program;

future horizontal development, secondary development, and tertiary recovery potential;

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

the completion of current HPAI projects and the effects thereof;

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

projected revenues, lifting costs, LOE; production taxes, DD&A expense, G&A expenses, other operating expenses, and taxes;

timing and amount of future production of oil and natural gas;

the benefits to be derived from acquisitions and divestitures;

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availability of pipeline capacity;

expected hedging positions and payments related to hedging contracts;

expectations regarding working capital, cash flow, and anticipated liquidity;

projected borrowings under our revolving credit facility and expectations regarding a new revolving credit facility;

plans regarding an MLP;

expected reductions in our debt levels and the steps taken to reduce our debt; and

marketing of oil and natural gas.

You are cautioned not to place undue reliance on such forward-looking statements, which speak only as of the date of this Report. Our actual results may differ significantly from the results discussed in the forward-looking statements. Such statements involve risks and uncertainties, including, but not limited to, the matters discussed in Item 1A. Risk Factors and elsewhere in this Report and in our other filings with the SEC. If one or more of these risks or uncertainties materialize, or should underlying assumptions prove incorrect, actual outcomes may vary materially from those indicated. We undertake no responsibility to update forward-looking statements for changes related to these or any other factors that may occur subsequent to this filing for any reason.

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

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

Counterparties. Our counterparties to commodity derivative contracts include: Bank of America, BNP Paribas, BP Corporation, Calyon, Deutsche Bank, J. Aron & Company, Morgan Stanley, and Wachovia. At December 31, 2006, we had committed greater than 10 percent of either our outstanding oil contracts or natural gas contracts to the following counterparties:

Counterparty	Percentage of Hedged Oil Production Committed	Percentage of Hedged Natural Gas Production Committed
BNP Paribas	7.6%	66.6%
Calyon	17.0%	14.3%
Deutsche Bank	34.9%	
J. Aron & Company	3.8%	19.0%
Wachovia	22.6%	

Performance on all of our contracts with J. Aron & Company is guaranteed by its parent, Goldman Sachs & Co. We feel the credit-worthiness of our current counterparties is sound and we do not anticipate any non-performance of contractual obligations. As long as each counterparty maintains an investment grade credit rating, pursuant to our hedging contracts, no collateral is required.

In order to mitigate the credit risk of financial instruments, we enter into master netting agreements with significant counterparties. The master netting agreement is a standardized, bilateral contract between

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a given counterparty and us. Instead of treating separately each financial transaction between our counterparty and us, the master netting agreement enables our counterparty and us to aggregate all financial trades and treat them as a single agreement. This arrangement benefits us in three ways. First, the netting of the value of all trades reduces the requirements of daily collateral posting by us. Second, default by counterparty under one financial trade can trigger rights for us to terminate all financial trades with such counterparty. Third, netting of settlement amounts reduces our credit exposure to a given counterparty in the event of close-out.

Commodity price sensitivity. The tables in this section provide information about derivative financial instruments to which we were a party as of December 31, 2006 that are sensitive to changes in oil and natural gas commodity prices.

We manage commodity price risk with swap contracts, put contracts, and collar contracts. Swap contracts provide a fixed price for a notional amount of sales volumes. Put contracts provide a fixed floor price on a notional amount of sales volumes while allowing full price participation if the relevant index price closes above the floor price. Collar contracts provide a floor price on a notional amount of sales volumes while allowing some additional price participation if the relevant index price closes above the floor price. Additionally, we may occasionally short sell put contracts with a strike price well below the floor price of a floor or collar in order to offset some of the cost of the contract. The unrealized mark-to-market loss on commodity derivatives at December 31, 2006 was approximately $56.4 million and is reflected in AOCL in our Consolidated Balance Sheet. As of December 31, 2006, the fair market value of our oil derivative contracts was a net $3.6 million asset and the fair market value of our natural gas derivative contracts was a net $10.0 million asset. Based on our open commodity derivative positions at December 31, 2006, a $1.00 increase in the NYMEX prices for oil and natural gas would result in a decrease to our net derivative fair value asset of approximately $12.9 million, while a $1.00 decrease in the NYMEX prices for oil and natural gas would result in an increase to our net derivative fair value asset of approximately $15.3 million. These amounts exclude deferred hedge premiums of $54.7 million at December 31, 2006 that is not subject to changes in commodity prices.

Oil Derivative Instruments

Period	Daily Floor Volume	Average Floor Price	Daily Short Floor Volume	Average Short Floor Price	Daily Swap Volume	Average Swap Price	Fair Market Value
	(Bbl)	(Per Bbl)	(Bbl)	(Per Bbl)	(Bbl)	(Per Bbl)	(In thousands)
Jan. Dec. 2007	8,000	$ 53.75		$	3,000	$ 36.75	$ (26,347)
Jan. June 2008	12,000	64.17	(4,000)	50.00	1,000	58.59	9,536
July Dec. 2008	8,000	66.25	(4,000)	50.00			8,471
Jan. Dec. 2009	5,000	70.00	(5,000)	50.00			11,972
							$ 3,632

Natural Gas Derivative Instruments

Period	Daily Floor Volume	Average Floor Price	Daily Short Floor Volume	Average Short Floor Price	Daily Swap Volume	Average Swap Price	Fair Market Value

	(Mcf)	(Per Mcf)	(Mcf)	(Per Mcf)	(Mcf)	(Per Mcf)	(In thousands)
Jan. Dec. 2007	32,500	$ 6.74		$	10,000	$ 4.99	$ 7,567
Jan. Dec. 2008	10,000	6.25					2,400
							$ 9,967

Interest rate sensitivity. At December 31, 2006, we had total long-term debt of $661.7 million, which is recorded net of discount of $6.3 million. Of this amount, $150 million bears interest at a fixed rate of

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6$^{1}/4$ percent, \$300 million bears interest at a fixed rate of 6 percent, and \$150 million bears interest at a fixed rate of 7$^{1}/4$ percent. The remaining outstanding long-term debt balance of \$68 million is under our revolving credit facility and is subject to floating market rates of interest that are linked to LIBOR.

At this level of floating rate debt, if the LIBOR rate increased one percent, we would incur an additional \$0.7 million of interest expense per year, and if the rate decreased one percent, we would incur \$0.7 million less. Additionally, if the LIBOR rate increased one percent, we estimate the fair value of our fixed rate debt at December 31, 2006 would decrease from \$561.4 million to \$527.0 million, and if the rate decreased one percent, we estimate the fair value would increase to \$598.7 million.

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ITEM 8. ***FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA***

Index to Consolidated Financial Statements

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REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

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

We have audited the accompanying consolidated balance sheets of Encore Acquisition Company (the Company) as of December 31, 2006 and 2005, and the related consolidated statements of operations, stockholders equity, and cash flows for each of the three years in the period ended December 31, 2006. These financial statements are the responsibility of the Company s management. Our responsibility is to express an opinion on these financial statements based on our audits.

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

In our opinion, the consolidated financial statements referred to above present fairly, in all material respects, the consolidated financial position of the Company at December 31, 2006 and 2005, and the consolidated results of its operations and its cash flows for each of the three years in the period ended December 31, 2006, in conformity with U.S. generally accepted accounting principles.

As explained in Note 2 to the consolidated financial statements, effective January 1, 2006, the Company adopted Statement of Financial Accounting Standards No. 123R, Share-Based Payment.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the effectiveness of the Company s internal control over financial reporting as of December 31, 2006, based on the criteria established in *Internal Control Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission, and our report dated February 28, 2007 expressed an unqualified opinion thereon.

/s/ Ernst & Young LLP

Fort Worth, Texas
February 28, 2007

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ENCORE ACQUISITION COMPANY
CONSOLIDATED BALANCE SHEETS

	December 31,	
	2006	2005
	(In thousands, except share and per share amounts)	
ASSETS		
Current assets:		
Cash and cash equivalents	$ 763	$ 1,654
Accounts receivable	81,470	76,960
Inventory	18,170	11,231
Derivatives	17,349	8,826
Deferred taxes	24,978	29,030
Prepaid expenses	2,988	5,656
Total current assets	145,718	133,357
Properties and equipment, at cost successful efforts method:		
Proved properties	2,033,914	1,691,175
Unproved properties	47,548	37,646
Accumulated depletion, depreciation, and amortization	(364,780)	(255,564)
	1,716,682	1,473,257
Other property and equipment	18,231	15,894
Accumulated depreciation	(7,791)	(5,366)
	10,440	10,528
Goodwill	60,606	59,046
Derivatives	40,715	17,316
Other	32,739	12,201
Total assets	$ 2,006,900	$ 1,705,705
LIABILITIES AND STOCKHOLDERS EQUITY		
Current liabilities:		
Accounts payable	$ 18,204	$ 27,281
Accrued lease operations expense	8,582	6,633
Accrued development capital	44,492	38,899
Interest payable	11,273	12,531
Production, ad valorem, and severance taxes payable	10,915	12,566
Accrued oil purchases	11,191	
Derivatives	60,448	76,515
Other	21,358	15,770

Total current liabilities	186,463	190,195
Derivatives	38,688	66,563
Future abandonment cost	19,205	14,430
Deferred taxes	282,825	213,268
Long-term debt	661,696	673,189
Other	1,158	1,279
Total liabilities	1,190,035	1,158,924
Commitments and contingencies (see Note 4)		
Stockholders equity:		
Preferred stock, $.01 par value, 5,000,000 shares authorized, none issued and outstanding		
Common stock, $.01 par value, 144,000,000 shares authorized, 53,046,675 and 48,784,846 issued and outstanding, respectively	531	488
Additional paid-in capital	457,201	316,619
Treasury stock, at cost, of 17,809 and 11,169 shares, respectively	(457)	(375)
Retained earnings	394,917	302,875
Accumulated other comprehensive loss	(35,327)	(72,826)
Total stockholders equity	816,865	546,781
Total liabilities and stockholders equity	$ 2,006,900	$ 1,705,705

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

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ENCORE ACQUISITION COMPANY
CONSOLIDATED STATEMENTS OF OPERATIONS

	Year Ended December 31,		
	2006	2005	2004
	(In thousands, except per share amounts)		
Revenues:			
Oil	$ 346,974	$ 307,959	$ 220,649
Natural gas	146,325	149,365	77,884
Oil marketing	147,563		
Total revenues	640,862	457,324	298,533
Expenses:			
Production:			
Lease operations	98,194	69,744	47,807
Production, ad valorem, and severance taxes	49,780	45,601	30,313
Depletion, depreciation, and amortization	113,463	85,627	48,522
Exploration	30,519	14,443	3,935
General and administrative	23,194	17,268	12,059
Oil marketing	148,571		
Derivative fair value (gain) loss	(24,388)	5,290	5,011
Loss on early redemption of debt		19,477	
Other operating	10,023	9,485	5,028
Total expenses	449,356	266,935	152,675
Operating income	191,506	190,389	145,858
Other income (expenses):			
Interest	(45,131)	(34,055)	(23,459)
Other	1,429	1,039	240
Total other income (expenses)	(43,702)	(33,016)	(23,219)
Income before income taxes	147,804	157,373	122,639
Income tax provision	(55,406)	(53,948)	(40,492)
Net income	$ 92,398	$ 103,425	$ 82,147
Net income per common share:			
Basic	$ 1.78	$ 2.12	$ 1.74
Diluted	1.75	2.09	1.72
Weighted average common shares outstanding:			
Basic	51,865	48,682	47,090
Diluted	52,736	49,522	47,738

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

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ENCORE ACQUISITION COMPANY
CONSOLIDATED STATEMENTS OF STOCKHOLDERS EQUITY

	Shares of Common Stock	Common Stock	Additional Paid-In Capital	Shares of Treasury Stock	Treasury Stock	Retained Earnings	Accumulated Other Comprehensive Loss	Total Stockholders Equity
	(In thousands)							
Balance at December 31, 2003	45,351	$ 454	$ 251,186		$	$ 117,365	$ (10,030)	$ 358,975
Exercise of stock options	303	3	4,118					4,121
Issuance of common stock	3,000	30	52,899					52,929
Non-cash stock-based compensation			1,770					1,770
Components of comprehensive income:								
Net income						82,147		82,147
Change in deferred hedge gain/loss, net of tax of $15,757							(26,367)	(26,367)
Total comprehensive income								55,780
Balance at December 31, 2004	48,654	487	309,973			199,512	(36,397)	473,575
Exercise of stock options and vesting of restricted stock	138	1	2,817					2,818
Purchase of treasury stock				(18)	(570)			(570)
Cancellation of treasury stock	(7)		(133)	7	195	(62)		
Non-cash stock-based compensation			3,962					3,962
Components of comprehensive income:								
Net income						103,425		103,425

Change in deferred hedge gain/loss, net of tax of $21,701							(36,429)	(36,429)
Total comprehensive income								66,996
Balance at December 31, 2005	48,785	488	316,619	(11)	(375)	302,875	(72,826)	546,781
Exercise of stock options and vesting of restricted stock	280	3	3,641					3,644
Purchase of treasury stock				(25)	(633)			(633)
Cancellation of treasury stock	(18)		(195)	18	551	(356)		
Issuance of common stock	4,000	40	127,061					127,101
Non-cash stock-based compensation			10,075					10,075
Components of comprehensive income:								
Net income						92,398		92,398
Change in deferred hedge gain/loss, net of tax of $22,365							37,499	37,499
Total comprehensive income								129,897
Balance at December 31, 2006	53,047	$ 531	$ 457,201	(18)	$ (457)	$ 394,917	$ (35,327)	$ 816,865

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

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ENCORE ACQUISITION COMPANY
CONSOLIDATED STATEMENTS OF CASH FLOWS

	Year Ended December 31,		
	2006	**2005**	**2004**
		(In thousands)	
Cash flows from operating activities:			
Net income	$ 92,398	$ 103,425	$ 82,147
Adjustments to reconcile net income to net cash provided by operating activities:			
Depletion, depreciation, and amortization	113,463	85,627	48,522
Non-cash exploration expense	28,128	10,706	2,761
Deferred taxes	51,220	56,032	38,579
Non-cash stock-based compensation expense	8,980	3,962	1,770
Non-cash derivative fair value	(10,434)	12,637	12,449
Loss on early redemption of debt		19,477	
Other non-cash expense	7,577	1,912	781
(Gain) loss on disposition of assets	(297)	352	271
Changes in operating assets and liabilities:			
Accounts receivable	(305)	(30,192)	(10,719)
Other current assets	(4,945)	(6,096)	(7,220)
Other assets	(365)	(4,798)	(5,568)
Accounts payable	1,833	(444)	(1,128)
Other current liabilities	10,080	39,669	9,176
Net cash provided by operating activities	297,333	292,269	171,821
Cash flows from investing activities:			
Proceeds from disposition of assets	1,522	753	703
Purchases of other property and equipment	(4,290)	(6,767)	(7,594)
Acquisition of oil and natural gas properties	(30,119)	(154,615)	(116,316)
Acquisition of Cortez Oil & Gas, Inc., net of cash acquired			(123,808)
Acquisition of Crusader Energy Corp., net of cash acquired		(91,095)	
Development of oil and natural gas properties	(340,582)	(321,836)	(186,455)
Advances to working interest partners	(22,425)		
Other	(1,536)		
Net cash used in investing activities	(397,430)	(573,560)	(433,470)
Cash flows from financing activities:			
Proceeds from issuance of common stock	128,000		53,900
Offering costs paid	(899)		(971)
Purchase of treasury stock	(633)	(570)	
Payment of debt issuance costs	(147)	(534)	(4,808)
Exercise of stock options	3,644	1,468	2,756
Proceeds from long-term debt	282,000	997,980	478,500
Payments on long-term debt	(294,000)	(719,852)	(278,500)

Payments of deferred commodity premiums	(7,848)		
Change in cash overdrafts	(10,911)	3,350	11,444
Net cash provided by financing activities	99,206	281,842	262,321
Increase (decrease) in cash and cash equivalents	(891)	551	672
Cash and cash equivalents, beginning of period	1,654	1,103	431
Cash and cash equivalents, end of period	$ 763	$ 1,654	$ 1,103

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

ENCORE ACQUISITION COMPANY
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

Note 1. Formation of the Company and Basis of Presentation

Encore Acquisition Company, a Delaware corporation (Encore or the Company), is a company engaged in the development of onshore North American oil and natural gas reserves. Since 1998, Encore has acquired high-quality assets and grown them through drilling, waterflood, and tertiary projects. Encore s properties are currently 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 Mid-Continent area, which includes the Arkoma and Anadarko Basins of Oklahoma, the North Louisiana Salt Basin, the East Texas Basin, and the Barnett Shale of northern Texas; and the Rockies, which includes non-CCA assets in the Williston and Powder River Basins of Montana and North Dakota, and the Paradox Basin of southeastern Utah.

Note 2. Summary of Significant Accounting Policies

Principles of Consolidation

The Company s consolidated financial statements include the accounts of wholly-owned and majority-owned subsidiaries. All material intercompany balances and transactions are eliminated.

Cash and Cash Equivalents

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

Inventories

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

	December 31,	
	2006	**2005**
	(In thousands)	
Warehouse inventory	$ 11,784	$ 9,019
Oil in pipelines	6,386	2,212
Total	$ 18,170	$ 11,231

Properties and Equipment

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

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ENCORE ACQUISITION COMPANY
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

If an exploratory well does not find reserves or does not find reserves in a sufficient quantity as to make them economically producible, the previously capitalized costs are expensed in the Company s Consolidated Statements of Operations and shown as a non-cash adjustment to net income in the Operating activities section of the Company s Consolidated Statements of Cash Flows in the period in which the determination was made. If a determination cannot be made within one year of the exploration well being drilled and no other drilling or exploration activities to evaluate the discovery are firmly planned, all previously capitalized costs associated with the exploratory well are expensed and shown as a non-cash adjustment to net income at that time. Re-drilling or directional drilling in a previously abandoned well is classified as development or exploratory based on whether it is in a proved or unproved reservoir. Expenditures for repairs and maintenance to sustain or increase production from the existing producing reservoir are charged to expense as incurred. Expenditures to recomplete a current well in a different unproved reservoir are capitalized pending determination that economic reserves have been added. If the recompletion is not successful, the expenditures are charged to expense. All capitalized costs associated with both development and exploratory wells are shown as Development of oil and natural gas properties in the Investing activities section of the Company s Consolidated Statements of Cash Flows.

Significant tangible equipment added or replaced is capitalized. Expenditures to construct facilities or increase the productive capacity from existing reserves are capitalized. Internal costs directly associated with the development of proved properties are capitalized as a cost of the property and are classified accordingly in the Company s consolidated financial statements. Capitalized costs are amortized on a unit-of-production basis over the remaining life of proved developed reserves or total proved reserves, as applicable. Natural gas volumes are converted to equivalent barrels of oil at the rate of six thousand cubic feet (Mcf) of natural gas to one barrel (Bbl) of oil.

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

Additionally, independent reserve engineers estimate the Company s reserves once a year on December 31. This results in a new DD&A rate which the Company uses for the preceding fourth quarter after adjusting for fourth quarter production. The Company internally estimates reserve additions and reclassifications of reserves from proved undeveloped to proved developed at the end of the first, second, and third quarters for use in determining a DD&A rate for the quarter.

In accordance with SFAS No. 144, Accounting for the Impairment or Disposal of Long-Lived Assets , the Company is required to assess the need for an impairment of capitalized costs of long-lived assets to be held and used, including proved oil and natural gas properties, whenever events and circumstances indicate that the carrying value of the asset may not be recoverable. If impairment is indicated based on a comparison of the asset s carrying value to its undiscounted expected future net cash flows, then it is recognized to the extent that the carrying value exceeds fair value. Expected future net cash flows are based on existing proved reserve and production information and pricing assumptions that management believes are representative of future economics. Any impairment charge incurred is expensed and reduces the recorded basis in the pool.

Unproved properties, the majority of the costs of which relate to the acquisition of leasehold interests, are assessed for impairment on a property-by-property basis for individually significant balances and on an aggregate basis for individually insignificant balances. If the assessment indicates an impairment, a loss is recognized by providing a valuation allowance at the level consistent with the level at which impairment was assessed. The impairment assessment is affected by economic factors such as the results of exploration activities, commodity price outlooks, remaining lease terms, and potential shifts in business strategy employed by management. In the case of individually insignificant balances, the amount of the impairment

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loss recognized is determined by amortizing the portion of these properties costs which we feel will not be transferred to proved over the average life of the lease.

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

Goodwill

Goodwill represents the excess of the purchase price over the estimated fair value of the net assets acquired in the purchases of Crusader Energy Corporation (Crusader) in October 2005 and Cortez Oil & Gas, Inc. (Cortez) in April 2004. See Note 3. Acquisitions for additional information. The Company tests goodwill for impairment on an annual basis or whenever indicators of impairment exist. The Company performed its annual impairment test at December 31, 2006, and determined that no impairment existed. If impairment is determined to exist, the impairment is measured based on a comparison of the carrying value of goodwill to the implied fair value of the goodwill. An impairment charge would be recognized for any amount by which the carrying value of goodwill exceeds its fair value. The goodwill test is performed at the reporting unit level. The Company has determined that it has only one reporting unit, which is oil and natural gas production in the United States.

Asset Retirement Obligations

SFAS No. 143, *Accounting for Asset Retirement* Obligations requires that the fair value of a liability for an asset retirement obligation (ARO) be recognized in the period in which the liability is incurred. For oil and natural gas properties, this is the period in which an oil or natural gas well is acquired or drilled. The ARO is capitalized as part of the carrying amount of the Company s oil and natural gas properties at its discounted fair value. The liability is then accreted each period until it is settled or the well is sold, at which time the liability is reversed. Estimates are based on historical experience in plugging and abandoning wells and estimated remaining field life based on reserve estimates. The Company does not provide for a market risk premium associated with ARO because a reliable estimate cannot be determined. See Note 5. AROs for additional information.

Stock-based Compensation

On January 1, 2006, the Company adopted the provisions of SFAS No. 123 (revised 2004), *Share-Based Payment* (SFAS 123R) using the modified prospective method. SFAS 123R is a revision of SFAS No. 123, *Accounting for Stock-Based Compensation* (SFAS 123) and supersedes Accounting Principles Board (APB) Opinion No. 25, *Accounting for Stock Issued to Employees* (APB 25). SFAS 123R eliminates the option of using the intrinsic value method of accounting previously available, and requires companies to recognize in the financial statements the cost of employee services received in exchange for awards of equity instruments based on the grant date fair value of those awards. Under the modified prospective method, compensation cost is recognized in the financial statements beginning with the effective date, based on the requirements of SFAS 123R, for all share-based payments granted after that date, and for all unvested awards granted prior to the effective date of SFAS 123R. The Company continues to utilize a standard option pricing model (i.e., Black-Scholes) to measure the fair value of employee stock options under SFAS 123R. Under SFAS 123R, the pro forma disclosures previously permitted under SFAS 123 are no longer be an alternative to financial statement recognition.

SFAS 123R also requires that the benefits associated with the tax deductions in excess of recognized compensation cost be reported as a financing cash flow. This requirement reduces net operating cash flows and increases net financing cash flows. The Company recognizes compensation costs related to awards

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with graded vesting on a straight-line basis over the requisite service period for each separately vesting portion of the award as if the award was, in-substance, multiple awards.

Prior to the adoption of SFAS 123R, employee stock options and restricted stock awards were accounted for under the provisions of APB 25. Accordingly, no compensation expense was recorded for stock options that were granted to employees or non-employee directors with an exercise price equal to or above the common stock price on the grant date. However, expense was recorded related to restricted stock granted to employees. Compensation expense associated with awards to employees who were eligible for retirement was recognized over the explicit service period of the award. Compensation expense for such awards that are granted subsequent to the adoption of SFAS 123R are fully expensed on the date of grant. If the Company had recognized compensation expense at the time an employee became eligible for retirement and had satisfied all performance requirements, non-cash stock-based compensation expense would have increased by $1.0 million and $0.3 million in 2005 and 2004, respectively. See Note 12. Employee Benefit Plans for additional information.

During 2005 and 2004, if compensation expense for the stock-based awards had been determined using the provisions of SFAS 123R, the Company s net income and net income per share would have been adjusted to the pro forma amounts indicated below:

	Year Ended December 31,	
	2005	**2004**
	(In thousands, except per share amounts)	
As Reported:		
Non-cash stock-based compensation, net of tax	$ 2,483	$ 1,108
Net income	103,425	82,147
Basic net income per share	2.12	1.74
Diluted net income per share	2.09	1.72
Pro Forma:		
Non-cash stock-based compensation, net of tax	3,091	2,289
Net income	102,817	80,966
Basic net income per share	2.11	1.72
Diluted net income per share	2.08	1.70

Segment Reporting

Segment reporting is not applicable to the Company as it has a single Company-wide management team that administers all properties as a whole rather than by discrete operating segments. The Company does not track all material costs to develop and operate its properties at a level lower than the total Company level, nor does its current internal reporting structure allow for accurate tracking at a lower level. Throughout the year, the Company allocates capital resources to projects on a project-by-project basis, across its entire asset base to maximize profitability without regard to individual areas or segments.

Major Customers

In 2006, Shell Trading Company (Shell) and ConocoPhillips Company (ConocoPhillips) accounted for 15 percent and 12 percent, respectively, of total sales of production. In 2005, 26 percent, 16 percent, 14 percent, and 10 percent of total oil and natural gas production was sold to Shell, Eighty-Eight Oil, BP, and Chevron, respectively. In 2004, 29 percent and 27 percent of total oil and natural gas production was sold to Shell and ConocoPhillips, respectively.

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ENCORE ACQUISITION COMPANY
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Income Taxes

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

Revenue Recognition

Revenues are recognized for the Company s share of jointly owned properties as oil and natural gas is produced and sold, net of royalties and net profits interest payments. Revenues are also reduced by any processing and other fees paid, except for transportation costs paid to third parties which are recorded as expense. Natural gas revenues are recorded using the sales method of accounting, whereby revenue is recognized as natural gas is sold rather than as produced. Royalties, net profits interests, and severance taxes are paid based upon the actual price received from the sales. To the extent actual quantities and values of oil and natural gas are unavailable for a given reporting period because of timing or information not received from third parties, the Company estimates and records the expected sales volumes and values for those properties. If the Company s underproduced imbalance position (i.e., the Company has cumulatively been over-allocated production) is greater than the Company s share of remaining reserves, the Company records a liability for the excess at year-end prices. The Company also does not recognize revenue for the production in tanks, oil marketed on behalf of joint owners in the Company s oil and natural gas properties, or oil in pipelines that has not been delivered to the purchaser. The Company s net oil inventories in pipelines were 146,284 barrels (Bbls) and 49,543 Bbls at December 31, 2006 and 2005, respectively. Natural gas imbalances at December 31, 2006 and 2005, were 188,757 million British thermal units (MMBTU) under-delivered to the Company and 204,400 MMBTU over-delivered to the Company, respectively.

Oil Marketing Revenues and Expenses and Buy/ Sell Transactions

In 2006, Encore 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. These purchases are conducted for strategic purposes to assist the Company in marketing its production by decreasing its dependence on individual markets. These activities allow the Company to aggregate larger volumes, facilitate its efforts to maximize the prices received for production, provide for a greater allocation of future pipeline capacity in the event of curtailments, and enable it to reach other markets.

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

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

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transactions in the oil and gas industry. The net gain/loss from Buy/ Sell transactions with produced oil volumes is recorded as an adjustment to Oil Revenues. The net gain/loss from Buy/ Sell transactions with oil volumes purchased from third parties is recorded as an adjustment to Oil Marketing Revenues.

Shipping Costs

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

Hedging and Related Activities

Encore uses various financial instruments for non-trading purposes to manage and reduce price volatility and other market risks associated with the Company s oil and natural gas production. These arrangements are structured to reduce the Company s exposure to commodity price decreases, but they can also limit the benefit the Company might otherwise receive from commodity price increases. Encore s risk management activity is generally accomplished through over-the-counter forward derivative or option contracts with large financial institutions.

During July 2006, the Company elected to discontinue hedge accounting prospectively for all commodity derivatives which were previously accounted for as hedges. From that point forward, all mark-to-market gains or losses on these derivative instruments are recorded in Derivative fair value (gain) loss in the Company s Consolidated Statements of Operations. The net deferred loss at the time of discontinuance of hedge accounting is being amortized to oil and natural gas revenues over the remaining term of the underlying contract.

Prior to July 2006, the Company used hedge accounting to account for its commodity derivatives. If a derivative did not qualify for hedge accounting, it was adjusted to fair value through earnings. However, if a derivative qualified for hedge accounting, depending on the nature of the hedge, changes in fair value could have been offset against the change in fair value of the hedged item through earnings or recognized in other comprehensive income until such time as the hedged item was recognized in earnings.

To qualify for cash flow hedge accounting, the cash flows from the hedging instrument had to be highly effective in offsetting changes in cash flows of the hedged item. In addition, all hedging relationships had to be designated, documented, and reassessed periodically.

The effective portion of the mark-to-market gain or loss on these derivative instruments was recorded in other comprehensive income in stockholders equity and reclassified into earnings in the same period in which the hedged transaction affects earnings. Any ineffective portion of the mark-to-market gain or loss was recognized into earnings immediately.

Comprehensive Income

Comprehensive income includes net income and other comprehensive income, which includes the change in unrealized gains and losses on derivative financial instruments. The Company chooses to show comprehensive income annually as part of its Consolidated Statements of Stockholders Equity.

Use of Estimates

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

ENCORE ACQUISITION COMPANY
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

financial statements and the reported amounts of revenues and expenses reported. Actual results could differ materially from those estimates.

Estimates made in preparing these consolidated financial statements include, among other things, the Company s estimated proved oil and natural gas reserve volumes used in calculating DD&A expense; the estimated future cash flows and fair value of properties used in determining the need for any impairment write-down; and the timing and amount of future abandonment costs used in calculating the Company s AROs. Future changes in the assumptions used could have a significant impact on reported results in future periods.

New Accounting Standards

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

In September 2006, the Financial Accounting Standards Board (FASB) issued SFAS 157. SFAS 157 clarifies the principle that fair value should be based on the assumptions market participants would use when pricing an asset or liability and establishes a fair value hierarchy that prioritizes the information used to develop those assumptions. Under SFAS 157, fair value measurements would be separately disclosed by level within the fair value hierarchy. SFAS 157 is effective for financial statements issued for fiscal years beginning after November 15, 2007, and interim periods within those fiscal years. Encore has not yet determined the impact, if any, that the implementation of SFAS 157 will have on its results of operations or financial condition.

FASB Interpretation No. 48, Accounting for Uncertainty in Income Taxes (FIN 48)

In June 2006, the FASB issued FIN 48. FIN 48 clarifies the accounting for uncertainty in income taxes recognized in a company s financial statements in accordance with SFAS No. 109, *Accounting for Income Taxes* . FIN 48 prescribes a recognition threshold and measurement attribute for the financial statement recognition and measurement of a tax position taken or expected to be taken in a tax return. FIN 48 is effective for fiscal years beginning after December 15, 2006. The Company is currently evaluating the effect, if any, FIN 48 will have, but currently it is not expected to have a material impact on the Company s financial condition, results of operations, or cash flows.

Note 3. Acquisitions

2005 Acquisitions

Williston Basin Acquisition. On September 8, 2005, the Company acquired oil and natural gas properties in the Williston Basin for a purchase price of approximately $28.6 million. Production from the properties, which are concentrated primarily in the Crane Field in Montana and the Tracy Mountain Field in North Dakota, is approximately 94 percent oil and 77 percent operated.

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

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

ENCORE ACQUISITION COMPANY
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

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

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

Kerr-McGee Acquisition. On November 30, 2005, the Company acquired oil and natural gas properties from Kerr-McGee Corporation for a purchase price of approximately $101.4 million. The acquired properties are located in the Levelland-Slaughter, Howard Glasscock, Nolley-McFarland, and Hutex fields in west Texas and the Oakdale, Calumet, and Rush Springs fields in western Oklahoma. The operating results for these properties are included in the Company s Consolidated Statements of Operations beginning in December 2005.

2004 Acquisitions

Cortez Acquisition. On April 14, 2004, the Company purchased all of the outstanding capital stock of Cortez, a privately held, independent oil and natural gas company, for a total purchase price of $127.0 million, which includes cash paid to Cortez former shareholders of $85.8 million, the repayment of $39.4 million of Cortez debt, and transaction costs of $1.8 million.

The acquired oil and natural gas properties are located primarily in the CCA of Montana, the Permian Basin of west Texas and southeastern New Mexico, and in the Mid-Continent area, including the Anadarko and Arkoma Basins of Oklahoma and the Barnett Shale of north Texas. Cortez operating results are included in the Company s Consolidated Statements of Operations beginning in April 2004.

ENCORE ACQUISITION COMPANY
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

Calculation of total purchase price:		
Cash paid to Cortez s former owners	$	85,805
Cortez debt repaid		39,449
Transaction costs		1,760
Total purchase price	$	127,014
Allocation of purchase price to the fair value of assets acquired:		
Cash	$	3,206
Other current assets		5,946
Proved oil and natural gas properties		120,503
Unproved oil and natural gas properties		3,011
Goodwill		37,908
Total assets acquired		170,574
Current liabilities		(5,673)
Non-current liabilities		(996)
Deferred taxes		(36,891)
Total liabilities assumed		(43,560)
Fair value of net assets acquired	$	127,014

The purchase price allocation resulted in $37.9 million of goodwill primarily as the result of the difference between the fair value of acquired oil and natural gas properties and their lower carryover tax basis, which resulted in deferred taxes of $36.9 million. Management believes the goodwill will be recovered through operating synergies resulting from the close proximity of the properties acquired to existing operations, particularly the additional interest in the CCA and Permian properties acquired through the Cortez acquisition. None of the goodwill is deductible for income tax purposes.

Overton. On June 17, 2004, the Company completed the acquisition of natural gas producing properties and undeveloped leases in the Overton Field located in Smith County, Texas for $83.1 million. The Overton Field assets are in the same core area as the Company s interests in Elm Grove Field and have similar geology. The operating results for these properties are included in the Company s Consolidated Statements of Operations beginning in July 2004.

Note 4. Commitments and Contingencies

Litigation

The Company is 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 the Company.

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ENCORE ACQUISITION COMPANY
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Leases

Encore leases office space and equipment that have remaining non-cancelable lease terms in excess of one year. The following table summarizes by year the remaining non-cancelable future payments under operating leases as of December 31, 2006 (in thousands):

2007	$ 1,818
2008	2,210
2009	2,094
2010	2,105
2011	2,094
Thereafter	3,897
	$ 14,218

The Company s operating lease rental expense was approximately $4.5 million, $3.1 million, and $3.5 million in 2006, 2005, and 2004, respectively.

ExxonMobil

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

Encore 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 Encore 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 Encore s monthly receipt of future 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 Encore has fulfilled its obligations under the commitment phase, Encore will be entitled to a 30 percent working interest in future drilling locations. Encore will have the right to propose and drill wells for as long as Encore is engaged in continuous drilling operations.

In April 2006, Encore commenced drilling in the development areas and by June 2006 operated four drilling rigs. A total of 24 wells were drilled during 2006, 12 of which were commitment wells. By the end of the year Encore had fulfilled it s obligation in two development areas (Brown Bassett Wolfcamp and Wilshire Devonian).

During 2006, we advanced $22.4 million to ExxonMobil for their portion of capital on drilling the commitment wells, of which $21.0 was outstanding at December 31, 2006. Of this amount, $3.0 million is included in Accounts receivable and $18.0 million is included in Other assets on the Company s Consolidated Balance Sheets. During 2006, the Company wrote off $1.9 million of ExxonMobil s portion of capital costs related to a dry hole in Other Operating on the Company s 2006 Consolidated Statement of Operations. As of December 31, 2006, Encore still had 12 wells to drill in order to fulfill its obligation under the joint development agreement.

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ENCORE ACQUISITION COMPANY
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Note 5. AROs

The Company s primary AROs relate to future plugging and abandonment expenses on oil and natural gas properties and related facilities disposal. The Company does not include a market risk premium in its risk estimates as the effect would not be material. As of December 31, 2006, the Company had $4.9 million held in an escrow account from which funds are released only for reimbursement of plugging and abandonment expenses on Encore s Bell Creek property. This amount is included in Other assets in the accompanying Consolidated Balance Sheets. The following table summarizes the changes in the Company s future abandonment liability, the long-term portion of which is recorded in Future abandonment cost on the Company s Consolidated Balance Sheets for 2006 and 2005:

	Year Ended December 31,	
	2006	2005
	(In thousands)	
Future abandonment liability at January 1	$ 14,430	$ 6,601
Acquisition of properties	785	2,221
Wells drilled	147	954
Accretion expense	743	515
Plugging and abandonment costs incurred	(1,466)	(745)
Revision of estimates	5,202	4,884
Future abandonment liability at December 31	$ 19,841	$ 14,430

During 2006, the Company increased its discounted estimate of future plugging liability by $5.2 million due to an increase in estimated future plugging cost per well and shortened field lives due to decreases in oil and natural gas prices.

Note 6. Capitalization of Exploratory Well Costs

The Company adopted FASB Staff Position (FSP) No. 19-1 Accounting for Suspended Well Costs (FSP 19-1) on July 1, 2005. FSP 19-1 amends SFAS 19 to permit the continued capitalization of exploratory well costs beyond one year if the well found a sufficient quantity of reserves to justify its completion as a producing well and the Company is making sufficient progress assessing the reserves and the economic and operating viability of the project. Upon the adoption of FSP 19-1, the Company evaluated all existing capitalized exploratory well costs and determined that there was no impact on the Company s results of operations, financial condition, or cash flows. The Company drilled its first exploratory well in the second quarter of 2004. The following table reflects the net changes in capitalized exploratory well costs during 2006, 2005, and 2004, and does not include amounts that were capitalized and subsequently expensed in the same period.

	Year Ended December 31,		
	2006	2005	2004
	(In thousands)		
Beginning balance at January 1	$ 6,560	$ 3,242	$
	13,048	6,560	3,242

Additions to capitalized exploratory well costs pending the determination of proved reserves			
Reclassification to proved property and equipment based on the determination of proved reserves	(1,457)	(996)	
Capitalized exploratory well costs charged to expense	(5,103)	(2,246)	
Total	$ 13,048	$ 6,560	$ 3,242

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

All of the capitalized exploratory well costs at December 31, 2006 related to wells in progress or wells for which drilling had been completed for less than one year.

Note 7. Accounts Payable and Other Current Liabilities

The Company s other current liabilities consisted of the following as of the dates indicated:

	December 31,	
	2006	2005
	(In thousands)	
Oil and natural gas revenues payable	$ 8,612	$ 4,544
Net profits payable	1,178	1,634
Acquired gas imbalances	3,173	408
Accrued bonus	5,665	5,299
Other	2,730	3,885
Total	$ 21,358	$ 15,770

Note 8. Long-Term Debt

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

	December 31,	
	2006	2005
	(In thousands)	
Revolving credit facility	$ 68,000	$ 80,000
6^{1}/4% Notes	150,000	150,000
6% Notes, net of unamortized discount of $4,892 and $5,317, respectively	295,108	294,683
7^{1}/4% Notes, net of unamortized discount of $1,412 and $1,494, respectively	148,588	148,506
Total	$ 661,696	$ 673,189

Senior Subordinated Notes

6^{1}/4% Notes. On April 2, 2004, the Company issued $150 million of its 6 1/4% Senior Subordinated Notes due April 15, 2014 (the 6^{1}/4% Notes). The Company received net proceeds of approximately $146.4 million after paying all costs associated with the offering. The net proceeds were used to fund the acquisition of Cortez and to reduce outstanding borrowings under the Company s revolving credit facility. Interest on the 6^{1}/4% Notes is due semi-annually on April 15 and October 15.

6% Notes. On July 13, 2005, the Company issued $300 million of its 6% Senior Subordinated Notes due July 15, 2015 (the 6% Notes). The Company received net proceeds of approximately $294.5 million from the private placement and used approximately $165.9 million of the net proceeds to redeem all of the Company s outstanding 8^{3}/8% Senior Subordinated Notes. The remaining net proceeds from the issuance were used to reduce outstanding borrowings under the Company s revolving credit facility. Interest on the 6% Notes is due semi-annually on January 15 and July 15.

7 1/4% Notes. On November 23, 2005, the Company issued $150 million of its 7 1/4% Senior Subordinated Notes due December 1, 2017 (the 7 1/4% Notes and together with the 6 1/4% Notes and the 6% Notes, the Notes). The net proceeds of approximately $148.5 million were used to reduce

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ENCORE ACQUISITION COMPANY
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

outstanding borrowings under the Company s revolving credit facility. Interest on the 7 1/4% Notes is due semi-annually on June 1 and December 1.

As of December 31, 2006 all of the Company s subsidiaries are subsidiary guarantors of the Notes. Since (i) each subsidiary guarantor is wholly owned by the Company, (ii) the Company has no assets or operations that are independent of its subsidiaries, (iii) the subsidiary guarantees are full and unconditional as well as joint and several, and (iv) all of the Company s subsidiaries are subsidiary guarantors, the Company has not included the financial statements of each subsidiary in this report. The subsidiary guarantors may without restriction transfer funds to the Company in the form of cash dividends, loans, and advances.

The indentures governing the Notes contain certain affirmative, negative, and financial covenants, which include (as defined in the indentures): (i) limitations on incurrence of additional debt, restrictions on asset dispositions, and restricted payments, (ii) maintenance of a 1.0 to 1.0 current ratio, and (iii) maintenance of EBITDA to interest expense ratio of 2.5 to 1.0. As of December 31, 2006, the Company was in compliance with all covenants of the Notes.

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

Revolving Credit Facility

On August 19, 2004, the Company entered into an amended and restated five-year senior secured revolving credit facility (the revolving credit facility) with a bank syndicate comprised of Bank of America, N.A. and other lenders. Availability under the revolving credit facility is determined through semi-annual borrowing base determinations and may be increased or decreased. The initial borrowing base was $400 million and may be increased to up to $750 million. The borrowing base as of December 31, 2006 was $550 million. The revolving credit facility matures on December 29, 2010. As of December 31, 2006, the Company had $460.9 million of available borrowing capacity under the revolving credit facility.

The Company s obligations under the revolving credit facility are guaranteed by its restricted subsidiaries and secured by a first priority-lien on substantially all of its proved oil and natural gas reserves and a pledge of the capital stock and equity interests of the Company s restricted subsidiaries.

Amounts outstanding under the revolving credit facility are subject to varying rates of interest based on (i) the amount outstanding under the revolving credit facility in relation to the borrowing base and (ii) whether the loan is a Eurodollar loan or a base rate loan. The following table summarizes the calculation of the various interest rates for both Eurodollar and base rate loans:

Ratio of Total Outstandings to Borrowing Base	**Eurodollar Loans(a)**	**Base Rate Loans(b)**
Less than .40 to 1	LIBOR + 1.000%	Base Rate + 0.000%
From .40 to 1 but less than .75 to 1	LIBOR + 1.250%	Base Rate + 0.000%
From .75 to 1 but less than .90 to 1	LIBOR + 1.500%	Base Rate + 0.250%
.90 to 1 or greater	LIBOR + 1.750%	Base Rate + 0.500%

(a) The London Interbank Offered Rate (LIBOR) is equal to the rate determined by Bank of America, N.A. to be the average British Bankers Association Interest Settlement Rate for deposits in dollars for a similar interest period (either one, two, three, or six months, or such other period that is twelve months of less as selected by Encore and consented to by each lender).

(b) 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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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

The borrowing base is redetermined each April 1 and October 1. The bank syndicate has the ability to request one additional borrowing base redetermination per year, and the Company is permitted to request two additional borrowing base redeterminations per year. Generally, if amounts outstanding ever exceed the borrowing base, the Company must reduce the amounts outstanding to the redetermined borrowing base within six months, provided that if amounts outstanding exceed the borrowing base as a result of any sale of the Company s assets or permitted subordinated debt, the Company must reduce the amounts outstanding immediately upon consummation of the sale.

Borrowings under the revolving credit facility may be repaid from time to time without penalty.

The revolving credit facility contains certain affirmative, negative, and financial covenants, which include (as defined in the revolving credit facility), but are not limited to: (i) limitations on the incurrence of additional debt, payment of dividends, repurchases of the Company s common stock, asset dispositions, and restricted payments, (ii) maintenance of at least a 1.0 to 1.0 current ratio, and (iii) maintenance of consolidated EBITDAX to interest expense ratio of at least 2.5 to 1.0. As of December 31, 2006, the Company was in compliance with all covenants under the revolving credit facility.

The Company incurs a commitment fee on the unused portion of the revolving credit facility determined based on the ratio of amounts outstanding under the revolving credit facility to the borrowing base in effect on such date. Any outstanding letters of credit reduce the availability under the Company s revolving credit facility. The following table summarizes the calculation of the Company s commitment fee:

Ratio of Total Outstandings to Borrowing Base	Commitment Fee Percentage
Less than .40 to 1	0.250%
From .40 to 1 but less than .90 to 1	0.375%
.90 to 1 or greater	0.500%

During 2006, 2005, and 2004, the weighted average interest rates for the Company s revolving credit facility were 4.5 percent, 6.5 percent, and 6.6 percent, respectively.

On April 4, 2006, the Company closed a public offering of its common stock for net proceeds of approximately $127.1 million, a portion of which was used to reduce borrowings under the revolving credit facility. See Note 10. Stockholders Equity for additional information.

Letters of Credit

At December 31, 2006, the Company had $21.1 million of outstanding letters of credit, $20.0 million of which related to the ExxonMobil joint development agreement. At December 31, 2005, the Company had $50.0 million of outstanding letters of credit at that were posted primarily with two counterparties to the Company s commodity derivative contracts and are used in lieu of cash margin deposits with those counterparties.

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ENCORE ACQUISITION COMPANY
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Long-Term Debt Maturities

The following table illustrates the Company s long-term debt maturities at December 31, 2006:

	Payments Due by Period				
	Total	2007	2008-2009	2010-2011	Thereafter
	(In thousands)				
$6^1/4\%$ Notes	$ 150,000	$	$	$	$ 150,000
6% Notes	300,000				300,000
$7^1/4\%$ Notes	150,000				150,000
Revolving credit facility	68,000			68,000	
Total	$ 668,000	$	$	$ 68,000	$ 600,000

Consolidated cash payments for interest were $46.4 million, $24.2 million, and $21.4 million for 2006, 2005, and 2004, respectively.

During 2006, 2005, and 2004, the weighted average interest rate for total indebtedness, including the Notes, the revolving credit facility, letters of credit, and related miscellaneous fees was 6.1 percent, 6.8 percent, and 7.7 percent, respectively.

Note 9. Taxes

Income Taxes

The components of the income tax provision are as follows for 2006, 2005, and 2004:

	Year Ended December 31,		
	2006	2005	2004
	(In thousands)		
Federal:			
Current	$ 3,785	$ (2,084)	$ 1,788
Deferred	48,327	53,147	35,470
Total federal	52,112	51,063	37,258
State (net of federal benefit):			
Current	401		125
Deferred	2,893	2,885	3,109
Total state	3,294	2,885	3,234
Income tax provision(a)	$ 55,406	$ 53,948	$ 40,492

(a) These amounts do not include the Company s excess tax benefit related to stock option exercises and vesting of restricted stock, which was recorded directly to additional paid-in capital, of $1.3 million, $1.4 million, and $1.3 million during 2006, 2005, and 2004, respectively.

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ENCORE ACQUISITION COMPANY
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

The following table reconciles income tax expense with income tax at the Federal statutory rate:

	Year Ended December 31,		
	2006	2005	2004
	(In thousands)		
Income before income taxes	$ 147,804	$ 157,373	$ 122,639
Tax at statutory rate	$ 51,731	$ 55,081	$ 42,923
State income taxes, net of federal benefit	3,294	2,885	3,234
Section 43 credits		(3,227)	(3,816)
Permanent and other	381	(791)	(1,849)
Income tax provision	$ 55,406	$ 53,948	$ 40,492

The Enhanced Oil Recovery credits available under Section 43 were fully phased out for the 2006 tax year due to high oil prices in 2005. Therefore, no credits were generated during 2006. In addition, a Texas franchise tax reform measure was signed into law on May 18, 2006, which caused the Texas franchise tax to be applicable to numerous types of entities that previously were not subject to the tax, including several of Encore s subsidiaries. The Company adjusted its net deferred tax balances using the new higher marginal tax rate it expects to be effective when those deferred taxes reverse resulting in a charge of $1.1 million during 2006.

Cash income tax payments in the amount of $0.5 million, $0.2 million, and $3.7 million were made in 2006, 2005, and 2004, respectively. The Company recognized in equity a benefit resulting from the reduction in income taxes payable related to the exercise of employee stock options and the vesting of restricted stock in the amount of $1.3 million, $1.4 million, and $1.4 million in 2006, 2005, and 2004, respectively.

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

	December 31,	
	2006	2005
	(In thousands)	
Current:		
Assets:		
Unrealized hedge loss in other comprehensive income	$ 20,049	$ 26,427
Derivative fair value loss	4,062	2,603
Other	867	
Total current deferred tax assets	$ 24,978	$ 29,030

ENCORE ACQUISITION COMPANY
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

	December 31,	
	2006	2005
	(In thousands)	
Long-term:		
Assets:		
Alternative minimum tax carryforward	$ 2,394	$ 2,073
Unrealized hedge loss in other comprehensive income	1,069	16,964
Derivative fair value loss	2,606	1,424
Section 43 credits	13,227	13,227
Other	5,615	3,004
Total long-term deferred tax assets	24,911	36,692
Liabilities:		
Book basis of oil and natural gas properties in excess of tax basis	(307,736)	(249,960)
Net long-term deferred tax liability	$ (282,825)	$ (213,268)

Taxes Other than Income Taxes

Taxes other than income taxes were comprised of the following for 2006, 2005, and 2004:

	Year Ended December 31,		
	2006	2005	2004
	(In thousands)		
Production and severance taxes	$ 43,458	$ 41,195	$ 27,491
Property and ad valorem taxes	6,322	4,406	2,822
Franchise, payroll, and other taxes	1,745	1,246	868
Total	$ 51,525	$ 46,847	$ 31,181

Note 10. Stockholders Equity

Public Offerings of Common Stock

In April 2006, the Company closed a public offering of 4.0 million shares of the Company s common stock at a price of $32.00 per share. The net proceeds of the offering, after deducting underwriting discounts and commissions and expenses of the offering, were approximately $127.1 million. The Company used the net proceeds of this offering to reduce outstanding borrowings under the revolving credit facility, to invest in oil and natural gas activities, and to pay general corporate expenses.

In June 2004, the Company closed a public offering of 3.0 million shares of common stock at a price to the public of $17.97 per share. The net proceeds of the offering, after underwriting discounts and commissions and expenses of the offering, were approximately $52.9 million. The Company used the net proceeds of this offering to reduce outstanding borrowings under the revolving credit facility and for general corporate purposes.

Shelf Registration Statement on Form S-3

On June 30, 2004, the Company filed a shelf registration statement on Form S-3 with the Securities Exchange Commission (SEC). Using this process, Encore may offer common stock, preferred stock, senior debt, and/or subordinated debt in one or more offerings with a total initial offering price of

ENCORE ACQUISITION COMPANY
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

up to $500 million. On November 23, 2005, the Company issued $150 million of 7 1/4% Notes under the shelf.

Stock Split

On June 15, 2005, the Company announced that its Board of Directors (the Board) approved a three-for-two split of the Company s outstanding common stock in the form of a stock dividend. The dividend was distributed on July 12, 2005, to stockholders of record at the close of business on June 27, 2005 (the Record Date). In lieu of issuing fractional shares, the Company paid cash for such fractional shares based on the closing price of the common stock on the Record Date.

Common Stock Option Exercises

During 2006, 2005, and 2004, employees of the Company exercised 178,174, 137,413, and 303,865 options, respectively, for which the Company received proceeds of $2.3 million, $1.5 million, and $2.8 million in 2006, 2005, and 2004, respectively.

Preferred Stock

The Company s authorized capital stock includes 5,000,000 shares of preferred stock, none of which were issued and outstanding at December 31, 2006 or 2005. The Company has no current plans to issue any shares of preferred stock.

Note 11. Earnings Per Share (EPS)

Under SFAS No. 128, *Earnings Per Share* , the Company must report basic EPS, which excludes the effect of potentially dilutive securities, and diluted EPS, which includes the effect of all potentially dilutive securities. EPS for the periods presented is based on the weighted average common shares outstanding for the period.

The following table reflects EPS data for 2006, 2005, and 2004:

	Year Ended December 31,		
	2006	**2005**	**2004**
	(In thousands, except per share data)		
Numerator:			
Net income	$ 92,398	$ 103,425	$ 82,147
Denominator:			
Denominator for basic EPS:			
Weighted average shares outstanding	51,865	48,682	47,090
Effect of dilutive options and diluted restricted stock(a)	871	840	648
Denominator for diluted EPS	52,736	49,522	47,738
Net income per common share:			
Basic	$ 1.78	$ 2.12	$ 1.74
Diluted	$ 1.75	$ 2.09	$ 1.72

(a) Options to purchase 190,406 shares of common stock were outstanding but not included in the above calculation of 2006 EPS because their effect would be antidilutive. There were no antidilutive options or shares of restricted stock for 2005 or 2004.

ENCORE ACQUISITION COMPANY
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Note 12. Employee Benefit Plans

401(k) Plan

The Company made contributions to the Encore Acquisition Company 401(k) Plan, which is a voluntary and contributory plan for eligible employees based on a percentage of employee contributions, that totaled $1.1 million, $0.8 million, and $0.6 million in 2006, 2005, and 2004, respectively. The Company s 401(k) plan does not currently allow employees to invest in securities of the Company. Effective February 1, 2007, the Company increased the percentage of employee contributions that will be matched.

Incentive Stock Plans

During 2000, the Board and stockholders approved the 2000 Incentive Stock Plan (the Plan). The Plan was amended and restated effective March 18, 2004. The purpose of the Plan is to attract, motivate, and retain selected employees of the Company and to provide the Company with the ability to provide incentives more directly linked to the profitability of the business and increases in shareholder value. All directors and full-time regular employees of the Company and its subsidiaries and affiliates are eligible to be granted awards under the Plan. The total number of shares of common stock reserved for issuance pursuant to the Plan is 4,500,000. As of December 31, 2006, there were 1,307,467 shares available for issuance under the Plan. Shares delivered or withheld for payment of the exercise price of an option, shares withheld for payment of tax withholding, or shares subject to options or other awards which expire or are terminated and restricted shares that are forfeited will again become available for issuance under the Plan. The Plan provides for the granting of cash awards, incentive stock options, non-qualified stock options, restricted stock, and stock appreciation rights at the discretion of the Compensation Committee of the Board. The Board has also created a Restricted Stock Award Committee having Jon S. Brumley, the Company s Chief Executive Officer and President, as its sole member. The Restricted Stock Award Committee may grant certain awards of restricted stock to non-executive employees at its discretion.

The Plan contains the following individual limits:

- an employee may not be granted awards covering or relating to more than 225,000 shares of common stock in any calendar year;
- a non-employee director may not be granted awards covering or relating to more than 15,000 shares of common stock in any calendar year; and
- an employee may not receive awards consisting of cash (including cash awards that are granted as performance awards) in respect of any calendar year having a value determined on the grant date in excess of $1.0 million.

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

Adoption of SFAS 123R. As previously discussed, on January 1, 2006, the Company adopted the provisions of SFAS 123R. SFAS 123R eliminates the option of using the intrinsic value method of accounting previously available, and requires companies to recognize in the financial statements the cost of employee services received in exchange for awards of equity instruments based on the grant date fair value of those awards.

The Company adopted the provisions of SFAS 123R using the modified prospective method, under which compensation cost is recognized in the financial statements for (i) share-based awards granted after

ENCORE ACQUISITION COMPANY
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

January 1, 2006 based on the requirements of SFAS 123R, and (ii) all unvested awards granted prior to January 1, 2006 based on criteria established in SFAS 123. As a result, the Company did not record a cumulative effect of accounting change related to the adoption.

Under SFAS 123R, equity instruments are not considered issued until all vesting conditions lapse. This differs from APB 25, which required the recording of restricted stock to equity with an off-setting contra-equity account which was amortized to expense over the vesting period. Because unvested restricted stock is no longer considered issued, the contra-equity account, Deferred compensation , is no longer reported as a separate component of stockholders equity. Certain equity balances as originally reported in the Company s 2005 Annual Report on Form 10-K have been retroactively restated to reflect the change. The following table summarizes the balances at December 31, 2005 as originally reported and as restated:

	December 31, 2005			
		As Originally Reported		As Restated
		(In thousands)		
Shares of common stock outstanding		49,368		48,785
Common stock	$	494	$	488
Additional paid-in capital	$	325,620	$	316,619
Deferred compensation	$	(9,007)	$	
Total stockholders equity	$	546,781	$	546,781

As a result of adopting SFAS 123R, the Company s income before income taxes and net income for 2006 are $1.7 million and $1.2 million lower, respectively, than if it had continued to account for share-based compensation under APB 25. Basic and diluted EPS for 2006 are each $0.02 per share lower than if the Company had continued to account for share-based compensation under APB 25.

The compensation cost and income tax benefit related to the Plan that has been recorded in the accompanying Consolidated Statements of Operations for 2006 was $9.0 million and $3.2 million, respectively. During 2006, the Company also capitalized $1.1 million of stock-based compensation cost as a component of Properties and equipment in the accompanying Consolidated Balance Sheets. Stock-based compensation expense has been allocated to lease operations expense, general and administrative expense, and exploration expense based on the allocation of the respective cash compensation.

Stock Options. The fair value of each option award granted during 2006, 2005, and 2004 was estimated on the date of grant using a Black-Scholes option valuation model based on the assumptions noted in the following table. The expected volatility is based on a combination of the historical volatility of the Company s stock and the historical stock volatility of certain peer companies for a period of time commensurate with the expected term of the award. For options granted in 2006, the Company used the simplified method prescribed by SEC Staff Accounting Bulletin No. 107 to estimate the expected term of the options, which is calculated as the average midpoint between each vesting date and the life of the option. The risk-free rate is based on the U.S. Treasury yield curve in effect at the time of grant for periods commensurate with the expected terms of the options.

	Year Ended December 31,		
	2006	2005	2004

Expected volatility	42.8%	46.0%	34.8%
Expected dividend yield	0.0%	0.0%	0.0%
Expected term (in years)	6.0	6.0	6.0
Risk-free interest rate	4.6%	3.7%	3.2%

ENCORE ACQUISITION COMPANY
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

The following table summarizes the changes in the number of outstanding options and their related weighted average strike prices during 2006, 2005, and 2004:

	Year Ended December 31,							
	2006				2005		2004	
	Number of Options	Weighted Average Strike Price	Weighted Average Remaining Contractual Term	Aggregate Intrinsic Value	Number of Options	Weighted Average Strike Price	Number of Options	Weighted Average Strike Price
				(In thousands)				
Outstanding at beginning of year	1,440,812	$ 13.20			1,520,586	$ 12.00	1,444,431	$ 9.91
Granted(a)	122,890	31.10			115,255	26.55	389,784	17.42
Forfeited	(48,410)	24.65			(57,616)	17.94	(9,764)	10.49
Exercised	(178,174)	13.14			(137,413)	9.07	(303,865)	9.07
Outstanding at end of year	1,337,118	14.44	6.0	$ 14,353	1,440,812	13.20	1,520,586	12.00
Exercisable at end of year	1,076,815	11.90	5.5	13,662	1,089,677	11.04	948,771	9.77

(a) During 2004, there were 37,500 stock options granted to non-employee directors.

The weighted average fair value per share of individual options granted during 2006, 2005, and 2004 was $14.96, $12.99, and $6.87, respectively. The total intrinsic value of options exercised during 2006, 2005, and 2004 was $2.4 million, $2.6 million, and $3.1 million, respectively. During 2006, 2005, and 2004, the Company received proceeds from the exercise of stock options of $2.3 million, $1.5 million, and $2.8 million, respectively, and realized tax benefits related to the exercises of $0.9 million, $0.5 million, and $0.7 million, respectively. At December 31, 2006, the Company had $1.2 million of total unrecognized compensation cost related to unvested stock options, which is expected to be recognized over a weighted average period of 1.6 years.

Additional information about common stock options outstanding and exercisable at December 31, 2006 is as follows:

Year of Grant	Range of Strike Prices Per Share	Weighted Number of Options Outstanding	Average Life (Years)	Weighted Average Strike Price	Number of Options Exercisable

2001	$8.33 to $9.33	482,325	4.5	$ 8.92	482,325
2002	$8.50 to $12.40	332,903	5.7	11.65	332,903
2003	$11.49 to $13.61	41,289	6.6	12.46	41,289
2004	$17.17 to $19.77	290,195	7.1	17.51	191,807
2005	$26.55	84,931	8.1	26.55	28,491
2006	$31.10	105,475	9.1	31.10	
		1,337,118	6.0	14.44	1,076,815

Subsequent to December 31, 2006, Encore issued 205,936 stock options to employees as part of the Company s annual incentive program.

Restricted Stock. During 2006, 2005, and 2004, the Company recognized expense related to restricted stock of $8.1 million, $4.0 million, and $1.8 million, respectively, and realized tax benefits related thereto of $0.4 million, $0.9 million, and $0.7 million, respectively. A summary of the status of the

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ENCORE ACQUISITION COMPANY
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Company s unvested restricted stock outstanding as of December 31, 2006, and changes during the year then ended, is presented below:

	Number of Shares	Weighted Average Grant Date Fair Value
Outstanding at January 1, 2006	583,274	$ 20.53
Granted	428,609	31.17
Vested	(101,377)	15.49
Forfeited	(81,887)	25.37
Outstanding at December 31, 2006	828,619	26.17

During 2006, 2005, and 2004, the Company issued 277,162, 130,854, and 102,106 shares, respectively, of restricted stock to employees which depend only on continued employment for vesting. The following table illustrates by year of grant the vesting of shares which remain outstanding at December 31, 2006 which depend only on continued employment for vesting:

	Year of Vesting				
Year of Grant	**2007**	**2008**	**2009**	**2010**	**Total**
2002	48,275				48,275
2003	19,080	19,080			38,160
2004	55,039	26,582	26,582		108,203
2005	5,508	82,206	76,698	76,698	241,110
2006	34,935	34,935	153,338	34,935	258,143
Total	162,837	162,803	256,618	111,633	693,891

During 2006, 2005, and 2004, the Company issued 151,447, 155,190, and 86,537 shares of restricted stock to employees that not only depend on the passage of time and continued employment, but on certain performance measures, for their vesting. The performance measures related to the 2004 and 2005 awards were met and therefore, vesting depends only on the passage of time and therefore, were included in the table above. The following table illustrates the vesting of shares which remain outstanding at December 31, 2006 that not only depend on the passage of time and continued employment, but on certain performance measures, assuming the performance measures are met, for their vesting:

	Year of Vesting				
Year of Grant	**2007**	**2008**	**2009**	**2010**	**Total**
2006	33,682	33,682	33,682	33,682	134,728

Total	33,682	33,682	33,682	33,682	134,728

Subsequent to December 31, 2006, the performance measures related to the 2006 awards were met and therefore, vesting depends only on the passage of time.

As of December 31, 2006, there was $10.5 million of total unrecognized compensation cost related to unvested, outstanding restricted stock, which is expected to be recognized over a weighted average period of 2.8 years. During 2006 and 2005, there were 101,377 and 81,883, respectively, that vested. Employees elected to satisfy minimum tax withholding obligations related to the vested restricted stock by allowing the Company to withhold 24,362 and 18,298 shares of common stock during 2006 and 2005, respectively. These shares are treated as treasury stock by the Company and have been reflected in the accompanying Consolidated Balance Sheets and Statements of Cash Flows as such.

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Subsequent to December 31, 2006, Encore issued 319,012 shares of restricted stock to employees as part of the Company s annual incentive compensation program.

Note 13. Financial Instruments

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

	December 31,			
	2006		2005	
	Book Value	Fair Value	Book Value	Fair Value
	(In thousands)			
Cash and cash equivalents	$ 763	$ 763	$ 1,654	$ 1,654
Accounts receivable	81,470	81,470	76,960	76,960
Plugging bond	732	838	690	843
Bell Creek escrow	4,887	4,902	3,982	3,986
Accounts payable	(18,204)	(18,204)	(27,281)	(27,281)
$6^1/4$% Notes	(150,000)	(140,625)	(150,000)	(145,500)
6% Notes	(295,108)	(275,250)	(294,683)	(279,000)
$7^1/4$% Notes	(148,588)	(145,500)	(148,506)	(150,000)
Revolving credit facility	(68,000)	(68,000)	(80,000)	(80,000)
Commodity derivative contracts	13,599	13,599	(86,794)	(86,794)
Deferred premiums on derivative contracts	(54,671)	(54,671)	(30,141)	(30,141)

The fair values of senior subordinated notes were determined using open market quotes as of December 31, 2006 and 2005. The difference between book value and fair value represents the premium or discount on that date. The book value of the revolving credit facility approximates the fair value as the interest rate is variable. The plugging bond and Bell Creek escrow are included in Other assets on the Company s Consolidated Balance Sheets and are classified as held to maturity and therefore, are recorded at amortized cost, which at December 31, 2006 and 2005 was less than fair value. Commodity contracts are marked-to-market each quarter in accordance with the provisions of SFAS 133.

Derivative Financial Instruments

The Company manages commodity price risk with swap contracts, put contracts, collars and floor spreads. Swap contracts provide a fixed price for a notional amount of volume. Put contracts provide a fixed floor price on a notional amount of volume while allowing full price participation if the relevant index price closes above the floor price. Collar contracts provide a floor price for a notional amount of volume while allowing some additional price participation if the relevant index price closes above the floor price. Additionally, the Company occasionally sells put contracts with a strike price well below the floor price of an existing or new floor. Combined, the short floor and long floor are called a floor spread.

The Company had $54.7 million of deferred premiums payable recorded at December 31, 2006, of which $30.4 million is considered long-term and is recorded in Derivative liabilities in the Company s Consolidated Balance Sheets. The premiums relate to various oil and natural gas floor contracts and are payable on a monthly basis from January 2007 to January 2010. The Company recorded these amounts at their net present value at the time the contract was entered into and accretes them up to their eventual settlement price by recording interest expense each period.

Commodity Contracts Mark-to-Market Accounting: Previously designated as hedges. Prior to July 2006, the Company used hedge accounting for certain of its derivative contracts, whereby the

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

effective portion of changes in the fair value of the contract was deferred in accumulated other comprehensive loss (AOCL) included in stockholders equity in the accompanying Consolidated Balance Sheets rather than recognized in current period earnings. During July 2006, the Company elected to discontinue hedge accounting prospectively for all commodity derivatives which were previously accounted for as hedges. While this change has no effect on cash flows, results of operations are affected by mark-to-market gains and losses, which fluctuate with the swings in oil and natural gas prices. At the point of dedesignation, the gains and losses to be amortized to oil and natural gas revenues as effective hedges were established and deferred in AOCL. The amortization of these amounts is included in oil and natural gas revenues with the revenues from the hedged production. All mark-to-market gains and losses from July 2006 forward are recognized in earnings through Derivative fair value (gain) loss in the accompanying Consolidated Statements of Operations rather than deferring such amounts in AOCL.

The following tables summarize the Company s open commodity derivative instruments as of December 31, 2006:

Oil Derivative Instruments

Period	Daily Floor Volume	Average Floor Price	Daily Short Floor Volume	Average Short Floor Price	Daily Swap Volume	Average Swap Price	Fair Market Value
	(Bbl)	(Per Bbl)	(Bbl)	(Per Bbl)	(Bbl)	(Per Bbl)	(In thousands)
Jan. Dec. 2007	8,000	$ 53.75		$	3,000	$ 36.75	$ (26,347)
Jan. June 2008	12,000	64.17	(4,000)	50.00	1,000	58.59	9,536
July Dec. 2008	8,000	66.25	(4,000)	50.00			8,471
Jan. Dec. 2009	5,000	70.00	(5,000)	50.00			11,972
							$ 3,632

Natural Gas Derivative Instruments

Period	Daily Floor Volume	Average Floor Price	Daily Short Floor Volume	Average Short Floor Price	Daily Swap Volume	Average Swap Price	Fair Market Value
	(Mcf)	(Per Mcf)	(Mcf)	(Per Mcf)	(Mcf)	(Per Mcf)	(In thousands)
Jan. Dec. 2007	32,500	$ 6.74		$	10,000	$ 4.99	$ 7,567
Jan. Dec. 2008	10,000	6.25					2,400
							$ 9,967

Commodity Contracts Mark-to-Market Accounting: Floor Spreads. In order to partially finance the cost of premiums on certain purchased floors, the Company may sell floors with a strike price below the strike price of the purchased floor. Together the two floors, known as a floor spread or put spread, have a lower premium cost than a traditional floor contract but provide price protection only down to the strike price of the short floor. During 2006, the Company entered into floor spreads with a $70 per Bbl purchased floor and a $50 per Bbl short floor for 4,000 Bbls per day in 2008 and 5,000 Bbls per day in 2009. As with the Company s other derivative contracts, these are marked-to-market each quarter through Derivative fair value (gain) loss in the accompanying Consolidated Statements of Operations. In the above table, the purchased floor component of these floor spreads has been included with the Company s other floor contracts and the short floor component is shown separately as negative volumes. The net cash flows per Bbl upon settlement of the contracts and payment of the related premiums when viewed together change depending on the New York Mercantile Exchange (NYMEX) oil price as follows:

When the NYMEX oil price is greater than $70 per Bbl, the Company pays the net purchased floor premium cost per Bbl.

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ENCORE ACQUISITION COMPANY
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

When the NYMEX oil price is greater than $50 per Bbl but less than $70 per Bbl, the Company receives settlements of $70 per Bbl less the NYMEX oil price and pays the net purchased floor premium cost per Bbl.

When the NYMEX oil price is below $50 per Bbl, the Company receives $20 per Bbl less the net purchased floor premium cost per Bbl.

Commodity Contracts Current Period Impact. As a result of derivative transactions for oil and natural gas, the Company recognized a pre-tax reduction in oil and natural gas revenues of approximately $60.3 million, $59.3 million, and $38.0 million in 2006, 2005, and 2004, respectively. The Company also recognized in the accompanying Consolidated Statements of Operations derivative fair value gains and losses related to (i) changes in the market value since the date of dedesignation of derivative contracts which were previously designated as hedges, (ii) changes in the market value of certain other commodity derivatives that were never designated as hedges, (iii) settlements on derivative contracts not designated as hedges, and (iv) ineffectiveness of derivative contracts designated as hedges prior to July 2006. The following table summarizes the components of derivative fair value gains and losses for 2006, 2005, and 2004:

	Year Ended December 31,		
	2006	2005	2004
	(In thousands)		
Designated cash flow hedges:			
Ineffectiveness Derivative commodity contracts	$ 1,748	$ 8,371	$ 5,018
Undesignated derivative contracts:			
Mark-to-market loss (gain):			
Interest rate swap		462	1,958
Commodity contracts	(17,279)	(2,050)	646
Settlements:			
Interest rate swap		(312)	(1,686)
Commodity contracts	(8,857)	(1,181)	(925)
Total derivative fair value loss (gain)	$ (24,388)	$ 5,290	$ 5,011

Commodity Contracts Future Period Impact. The components of AOCL consisted of the following as of the dates indicated:

	December 31,	
	2006	2005
	(In thousands)	
Deferred loss on commodity derivatives, net of tax	$ (35,327)	$ (72,918)
Deferred gain on interest rate swap, net of tax		92
Accumulated other comprehensive loss	$ (35,327)	$ (72,826)

In 2007, the Company expects to reclassify $53.6 million of deferred losses associated with its dedesignated commodity contracts from AOCL to oil and natural gas revenues. The remaining pretax amount of AOCL will be reclassified to oil and natural gas revenues in 2008. The Company also expects to reclassify approximately $20.0 million of net deferred income tax benefits during 2007 from AOCL to income tax benefit.

Counterparty Risk. Encore s counterparties to commodity derivative contracts include: Bank of America, BNP Paribas, BP Corporation, Calyon, Deutsche Bank, J. Aron & Company, Morgan Stanley,

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ENCORE ACQUISITION COMPANY
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

and Wachovia. At December 31, 2006, the Company had committed greater than 10 percent of either its outstanding oil contracts or natural gas contracts to the following counterparties:

Counterparty	Percentage of Hedged Oil Production Committed	Percentage of Hedged Natural Gas Production Committed
BNP Paribas	7.6%	66.6%
Calyon	17.0%	14.3%
Deutsche Bank	34.9%	
J. Aron & Company	3.8%	19.0%
Wachovia	22.6%	

Performance on all contracts with J. Aron & Company are guaranteed by its parent, Goldman Sachs & Co. The Company feels the credit-worthiness of the current counterparties is sound and the Company does not anticipate any non-performance of contractual obligations. As long as each counterparty maintains an investment grade credit rating, pursuant to Encore s hedging contracts, no collateral is required.

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

Note 14. Related Party Transactions

The Company paid $3.3 million, $1.0 million, and $0.3 million to affiliates of Hanover Compressor Company (Hanover) in 2006, 2005, and 2004, respectively, for compressors and field compression services. Mr. I. Jon Brumley, the Company s Chairman of the Board, also serves as a director of Hanover.

The Company paid $0.4 million, $0.4 million, and $0.2 million to affiliates of Kinder Morgan, Inc. (Kinder Morgan) in 2006, 2005, and 2004, respectively, for its portion of production costs of certain non-operated wells. Mr. Ted A. Gardner, a member of the Company s Board, also serves as a director of Kinder Morgan.

Note 15. Subsequent Events

Acquisitions

On January 16, 2007, the Company entered into a purchase and sale agreement to acquire oil and natural gas producing properties and related assets in the Big Horn Basin from certain subsidiaries of Anadarko Petroleum Corporation (Anadarko), for a purchase price of $400 million, subject to customary purchase price adjustments and closing conditions. The properties are comprised of the Elk Basin Unit and the Gooseberry Unit in Park County, Wyoming. The Big Horn Basin properties currently produce approximately 4 thousand barrels of oil equivalent per day (MBOE/ D) net with an additional 350 BOE/ D net of natural gas liquids produced by the Elk Basin Gas Plant. In connection with the acquisition, the Company purchased put contracts on approximately two-thirds of the acquisition s

ENCORE ACQUISITION COMPANY
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

expected production volumes at $65.00 per Bbl for the remainder of 2007 and all of 2008. The Big Horn Basin acquisition is expected to close in March 2007.

On January 23, 2007, the Company entered into a purchase and sale agreement to acquire oil and natural gas producing properties in the Williston Basin from certain subsidiaries of Anadarko for a purchase price of $410 million, subject to customary purchase price adjustments and closing conditions. The properties are comprised of 50 different fields across Montana and North Dakota. As part of this acquisition, the Company is also acquiring approximately 70,000 net acres and 800 BOE/ D of production in the Bakken play in Montana and North Dakota. The Williston Basin properties currently produce approximately 5 MBOE/ D net, will be 85 percent operated by Encore. In connection with the acquisition, the Company purchased put contracts on approximately 80 percent of the acquisition s expected production volumes at an average price of $57.50 per Bbl for the remainder of 2007 and all of 2008. The Williston Basin acquisition is expected to close in April 2007.

Encore intends to finance the combined acquisitions through cash flows from operations and borrowings under one or more credit facilities.

Master Limited Partnership (MLP)

On January 17, 2007, the Company announced an intention to form a master limited partnership (MLP) that will engage in an initial public offering of common units representing limited partner interests. The MLP is expected to own certain Big Horn Basin properties to be acquired from certain subsidiaries of Anadarko and certain of the Company s legacy oil and gas properties. The Company expects that a registration statement on Form S-1 for the MLP will be filed with the SEC in the second quarter of 2007 with respect to an offering of units representing limited partnership interests in the MLP. Any sale of securities in the MLP would be registered under the Securities Act of 1933, and such units would only be offered and sold by means of a prospectus. This Report does not constitute an offer to sell or the solicitation of any offer to buy any securities of the MLP, and there will not be any sale of any such securities in any state in which such offer, solicitation, or sale would be unlawful prior to registration or qualification under the securities laws of such state.

Revolving Credit Facility

As a result of the proposed acquisitions from Anadarko, the Company expects to enter into a new $1.25 billion five-year revolving credit facility in March 2007 with a $650 million initial borrowing base that will increase to $950 million upon completion of the Williston Basin acquisition, which is currently scheduled for April 2007. The Company also expects that one of its subsidiaries will enter into a $300 million five-year revolving credit facility in March 2007 with a $115 million borrowing base and a $10 million overadvance feature, which will be non-recourse to the Company.

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ENCORE ACQUISITION COMPANY
SUPPLEMENTARY INFORMATION

Capitalized Costs and Costs Incurred Relating to Oil and Natural Gas Producing Activities

The capitalized cost of oil and natural gas properties was as follows as of the dates indicated:

	December 31,	
	2006	2005
	(In thousands)	
Properties and equipment, at cost successful efforts method:		
Proved properties	$ 2,033,914	$ 1,691,175
Unproved properties	47,548	37,646
Accumulated depletion, depreciation, and amortization	(364,780)	(255,564)
	$ 1,716,682	$ 1,473,257

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

	Year Ended December 31,		
	2006	2005	2004
	(In thousands)		
Acquisitions:			
Proved properties	$ 4,486	$ 224,469	$ 204,907
Unproved properties	24,462	21,205	33,926
Asset retirement obligations	785	2,221	1,165
Total acquisitions	29,733	247,895	239,998
Development:			
Drilling and exploitation	253,484	268,520	157,092
Asset retirement obligations	147	954	467
Total development	253,631	269,474	157,559
Exploration:			
Drilling and exploitation	92,839	53,316	29,363
Geological and seismic	1,720	3,095	979
Delay rentals	646	635	204
Total exploration	95,205	57,046	30,546
Total costs incurred	$ 378,569	$ 574,415	$ 428,103

Oil & Natural Gas Producing Activities Unaudited

The estimates of the Company s proved oil and natural gas reserves, which are located entirely within the United States, were prepared in accordance with guidelines established by the SEC and the FASB. Proved oil and natural gas reserve quantities are based on estimates prepared by Miller and Lents, Ltd., who are independent petroleum engineers.

Future prices received for production and future production costs may vary, perhaps significantly, from the prices and costs assumed for purposes of these estimates. There can be no assurance that the proved reserves will be developed within the periods assumed or that prices and costs will remain constant. Actual production may not equal the estimated amounts used in the preparation of reserve projections. In accordance with SEC guidelines, the Company s estimates of future net cash flows from the properties and

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ENCORE ACQUISITION COMPANY
SUPPLEMENTARY INFORMATION (Continued)

the representative value thereof are made using oil and natural gas prices in effect as of the dates of such estimates and are held constant throughout the life of the properties. Year-end prices used in estimating net cash flows were as follows as of the dates indicated:

	December 31,		
	2006	**2005**	**2004**
Oil (per Bbl)	$ 61.06	$ 61.04	$ 43.46
Natural gas (per Mcf)	5.48	9.44	6.19

The Company s reserve and production quantities from the CCA properties have been reduced by the amounts attributable to the net profits interest. The net profits interest on the Company s CCA properties has been deducted from future cash inflows in the calculation of Standardized Measure. In addition, net future cash inflows have not been adjusted for hedge positions outstanding at the end of the year. The future cash flows are reduced by estimated production costs and development costs, which are based on year-end economic conditions and held constant throughout the life of the properties, and by the estimated effect of future income taxes. Future income taxes are based on statutory income tax rates in effect at year-end, the Company s tax basis in its proved oil and natural gas properties, and the effect of net operating loss, alternative minimum tax, and Section 43 tax credits.

There are numerous uncertainties inherent in estimating quantities of proved reserves and in projecting future rates of production and timing of development expenditures. Oil and natural gas reserve engineering is and must be recognized as a subjective process of estimating underground accumulations of oil and natural gas that cannot be measured in any exact way, and estimates of other engineers might differ materially from those included 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. Accordingly, reserve estimates are often materially different from the quantities of oil and natural gas that are ultimately recovered. Reserve estimates are integral to management s analysis of impairments of oil and natural gas properties and the calculation of DD&A on these properties.

Estimated net quantities of proved oil and natural gas reserves of the Company were as follows as of the dates indicated:

	December 31,		
	2006	**2005**	**2004**
Proved reserves:			
Oil (MBbl)	153,434	148,387	134,048
Natural gas (MMcf)	306,764	283,865	234,030
Combined (MBOE)	204,561	195,698	173,053
Proved developed reserves:			
Oil (MBbl)	94,246	101,505	97,114
Natural gas (MMcf)	235,049	229,950	156,919
Combined (MBOE)	133,421	139,830	123,267

Encore is committed to sell at least 4,500 Bbls of oil per day at a floating market price through 2009.

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ENCORE ACQUISITION COMPANY
SUPPLEMENTARY INFORMATION (Continued)

The changes in proved reserves were as follows for 2006, 2005, and 2004:

	Oil (MBbl)	Natural Gas (MMcf)	Oil Equivalent (MBOE)
Balance, December 31, 2003	117,732	138,950	140,890
Acquisitions of minerals-in-place	7,853	86,314	22,239
Extensions and discoveries	4,226	27,248	8,768
Improved recovery	11,826	(80)	11,812
Revisions of estimates	(910)	(4,313)	(1,629)
Production	(6,679)	(14,089)	(9,027)
Balance, December 31, 2004	134,048	234,030	173,053
Acquisitions of minerals-in-place	8,333	38,781	14,796
Extensions and discoveries	2,780	28,073	7,459
Improved recovery	11,510	1,132	11,699
Revisions of estimates	(1,413)	2,908	(928)
Production	(6,871)	(21,059)	(10,381)
Balance, December 31, 2005	148,387	283,865	195,698
Acquisitions of minerals-in-place	25	235	64
Extensions and discoveries	3,269	78,861	16,412
Improved recovery	10,935	941	11,092
Revisions of estimates	(1,847)	(33,682)	(7,461)
Production	(7,335)	(23,456)	(11,244)
Balance, December 31, 2006	153,434	306,764	204,561

The Standardized Measure of discounted estimated future net cash flows related to proved oil and natural gas reserves was as follows as of the dates indicated:

	December 31, 2006	December 31, 2005	December 31, 2004
	(In thousands)		
Net future cash inflows	$ 9,291,007	$ 10,414,091	$ 6,651,858
Future production costs	(3,668,897)	(3,690,974)	(2,389,359)
Future development costs	(371,396)	(250,554)	(194,746)
Future abandonment costs	(134,103)	(121,553)	(49,859)
Future income tax expense	(1,499,290)	(1,934,504)	(1,221,933)
Future net cash flows	3,617,321	4,416,506	2,795,961
10% annual discount	(2,155,514)	(2,498,035)	(1,630,342)

Standardized measure of discounted estimated future net cash flows	$ 1,461,807	$ 1,918,471	$ 1,165,619

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ENCORE ACQUISITION COMPANY
SUPPLEMENTARY INFORMATION (Continued)

The primary changes in the Standardized Measure of discounted estimated future net cash flows were as follows for 2006, 2005, and 2004:

	Year Ended December 31,		
	2006	2005	2004
	(In thousands)		
Standardized measure, beginning of year	$ 1,918,471	$ 1,165,619	$ 736,939
Net change in sales price and production costs	(634,033)	531,793	430,310
Acquisitions of mineral-in-place	539	256,257	242,855
Extensions, discoveries, and improved recovery	141,211	229,929	150,112
Revisions of quantity estimates	(62,615)	(15,455)	(15,217)
Sales, net of production costs	(340,036)	(357,028)	(222,995)
Development costs incurred during the year	253,484	268,520	157,092
Accretion of discount	191,847	116,562	73,694
Change in estimated future development costs	(185,212)	(199,158)	(276,027)
Net change in income taxes	248,491	(247,937)	(145,042)
Change in timing and other	(70,340)	169,369	33,898
Standardized measure, end of year	$ 1,461,807	$ 1,918,471	$ 1,165,619

Selected Quarterly Financial Data

The following table sets forth selected quarterly financial data for 2006 and 2005:

	Quarter			
	First	Second	Third	Fourth
	(In thousands, except per share data)			
2006				
Revenues, as reported	$ 116,216	$ 133,471	$ 177,697	$ 157,710
Plus: change in marketing presentation	31,746	24,022		
Revenues, as restated	$ 147,962	$ 157,493	$ 177,697	$ 157,710
Operating income	$ 40,846	$ 47,594	$ 78,002	$ 25,064
Net income	$ 17,936	$ 22,235	$ 42,135	$ 10,092
Basic income per common share	$ 0.37	$ 0.42	$ 0.80	$ 0.19
Diluted income per common share	$ 0.36	$ 0.42	$ 0.78	$ 0.19
2005				
Revenues	$ 91,581	$ 99,717	$ 127,572	$ 138,454
Operating income	$ 39,917	$ 43,401	$ 38,911	$ 68,160
Net income	$ 21,784	$ 23,668	$ 20,854	$ 37,119
Basic income per common share	$ 0.45	$ 0.49	$ 0.43	$ 0.76
Diluted income per common share	$ 0.44	$ 0.48	$ 0.42	$ 0.75

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

ENCORE ACQUISITION COMPANY

ITEM 9. ***CHANGES IN AND DISAGREEMENTS WITH ACCOUNTANTS ON ACCOUNTING AND FINANCIAL DISCLOSURE***

None.

ITEM 9A. ***CONTROLS AND PROCEDURES***

Evaluation of Disclosure Controls and Procedures

As of the end of the period covered by this Report, we carried out an evaluation, under the supervision and with the participation of our management, including our Chief Executive Officer and Chief Financial Officer, of the effectiveness of the design and operation of our disclosure controls and procedures (as defined in Rule 13a-15(e) of the Exchange Act. Based upon that evaluation, the Chief Executive Officer and the Chief Financial Officer concluded that, as of December 31, 2006, our disclosure controls and procedures were effective to provide reasonable assurance that information required to be disclosed by the Company in the reports that it files or submits under the Exchange Act is recorded, processed, summarized, and reported within the time periods specified in applicable rules and forms.

Management s Report on Internal Control Over Financial Reporting

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

As of December 31, 2006, management assessed the effectiveness of the Company s internal control over financial reporting based on the criteria for effective internal control over financial reporting established in Internal Control Integrated Framework , issued by the Committee of Sponsoring Organizations of the Treadway Commission. Based on that assessment, management determined that the Company maintained effective internal control over financial reporting as of December 31, 2006, based on those criteria.

Ernst & Young, LLP, the independent registered public accounting firm that audited the consolidated financial statements of the Company included in this Annual report on Form 10-K, has issued an attestation report on management s assessment of the effectiveness of the Company s internal control over financial reporting as of December 31, 2006. The report, which expresses unqualified opinions on management s assessment and on the effectiveness of the Company s internal control over financial reporting as of December 31, 2006, is included below under the heading Report of Independent Registered Public Accounting Firm on Internal Control Over Financial Reporting .

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ENCORE ACQUISITION COMPANY

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

The Board of Directors and Stockholders of
Encore Acquisition Company:

We have audited management s assessment, included in the accompanying Management s Report on Internal Control over Financial Reporting appearing under Item 9A, that Encore Acquisition Company (the Company) maintained effective internal control over financial reporting as of December 31, 2006 based on criteria established in Internal Control Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (the COSO criteria). The Company s management is responsible for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting. Our responsibility is to express an opinion on management s assessment and an opinion on the effectiveness of the company s internal control over financial reporting based on our audit.

We conducted our audit in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether effective internal control over financial reporting was maintained in all material respects. Our audit included obtaining an understanding of internal control over financial reporting, evaluating management s assessment, testing and evaluating the design and operating effectiveness of internal control, and performing such other procedures as we considered necessary in the circumstances. We believe that our audit provides a reasonable basis for our opinion.

A company s internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company s internal control over financial reporting includes those policies and procedures that (1) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (2) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (3) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company s assets that could have a material effect on the financial statements.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

In our opinion, management s assessment that Encore Acquisition Company maintained effective internal control over financial reporting as of December 31, 2006, is fairly stated, in all material respects, based on the COSO criteria. Also, in our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2006, based on the COSO criteria.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the consolidated balance sheets of the Company as of December 31, 2006 and 2005, and the related consolidated statements of operations, stockholders equity, and cash flows for each of the three years in the period ended December 31, 2006, and our report dated February 28, 2007 expressed an unqualified opinion thereon.

/s/ Ernst & Young LLP

Fort Worth, Texas
February 28, 2007

ENCORE ACQUISITION COMPANY

Changes in Internal Control over Financial Reporting

There were no changes in our internal control over financial reporting that occurred during the quarter ended December 31, 2006 that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

ITEM 9B. ***OTHER INFORMATION***

None.

PART III

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

The information required in response to this item will be set forth in our definitive proxy statement for the 2007 annual meeting of stockholders and is incorporated herein by reference.

We have adopted a Code of Business Conduct and Ethics covering our directors, officers, and employees, which is available free of charge on our Internet website (www.encoreacq.com). We will post on our web site any amendments to the Code of Business Conduct and Ethics or waivers of the Code of Business Conduct and Ethics for directors and executive officers.

ITEM 11. ***EXECUTIVE COMPENSATION***

The information required in response to this item will be set forth in our definitive proxy statement for the 2007 annual meeting of stockholders and is incorporated herein by reference.

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

The information required in response to this item will be set forth in our definitive proxy statement for the 2007 annual meeting of stockholders and is incorporated herein by reference.

The following table sets forth information about our common stock that may be issued under equity compensation plans as of December 31, 2006:

	(a) Number of Securities to Be Issued upon Exercise of Outstanding Options, Warrants and Rights(2)	(b) Weighted-Average Exercise Price of Outstanding Options, Warrants and Rights	(c) Number of Securities Remaining Available for Future Issuance Under Equity Compensation Plans (Excluding Securities Reflected in Column(a))
Equity compensation plans approved by security holders(1)	1,337,118	$ 14.44	1,307,467
Equity compensation plans not approved by security holders			
Total	1,337,118	$ 14.44	1,307,467

(1) The 2000 Incentive Stock Plan is the Company s only equity compensation plan.

(2) Excludes 828,919 shares of restricted stock.

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ENCORE ACQUISITION COMPANY

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

The information required in response to this item will be set forth in our definitive proxy statement for the 2007 annual meeting of stockholders and is incorporated herein by reference.

ITEM 14. ***PRINCIPAL ACCOUNTING FEES AND SERVICES***

The information required in response to this item will be set forth in our definitive proxy statement for the 2007 annual meeting of stockholders and is incorporated herein by reference.

PART IV

ITEM 15. ***EXHIBITS, FINANCIAL STATEMENT SCHEDULES***

(a) The following documents are filed as a part of this Report:

1. Financial Statements:

2. Financial Statement Schedules:

All financial statement schedules have been omitted because they are not applicable or the required information is presented in the financial statements or the notes to the consolidated financial statements.

(b) Exhibits

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

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ENCORE ACQUISITION COMPANY
INDEX TO EXHIBITS

Exhibit No.	Description
2.1	Purchase and Sale Agreement dated January 16, 2007 among Clear Fork Pipeline Company, Howell Petroleum Corporation, Kerr-McGee Oil & Gas Onshore LP, and the Company (incorporated by reference to Exhibit 2.1 of the Company s Current Report on Form 8-K, filed with the SEC on January 17, 2007).
2.2	Purchase and Sale Agreement dated January 23, 2007 among Howell Petroleum Corporation and Kerr-McGee Oil & Gas Onshore LP, as Sellers, and the Company, as Purchaser (incorporated by reference to Exhibit 2.1 of the Company s Current Report on Form 8-K, filed with the SEC on January 26, 2007).
3.1	Second Amended and Restated Certificate of Incorporation of the Company (incorporated by reference to the Company s Quarterly Report on Form 10-Q for the fiscal quarter ended September 30, 2001, filed with the SEC on November 7, 2001).
3.1.2	Certificate of Amendment to Second Amended and Restated Certificate of Incorporation of the Company (incorporated by reference to the Company s Quarterly Report on Form 10-Q for the fiscal quarter ended March 31, 2005, filed with the SEC on May 5, 2005).
3.2	Second Amended and Restated Bylaws of the Company (incorporated by reference to the Company s Quarterly Report on Form 10-Q for the fiscal quarter ended September 30, 2001, filed with the SEC on November 7, 2001).
4.1	Specimen certificate of the Company (incorporated by referenced to Exhibit 4.1 to Registration Statement on Form S-1, Registration No. 333-47540, filed with the SEC on December 15, 2000).
4.2.1	Indenture, dated as of April 2, 2004, among the Company, the subsidiary guarantors party thereto and Wells Fargo Bank, National Association, with respect to the 6.25% Senior Subordinated Notes due 2014 (incorporated by reference to Exhibit 4.1 of the Company s Registration Statement on Form S-4 (Registration No. 333-117025) filed with the SEC on June 30, 2004).
4.2.2	Form of 6.25% Senior Subordinated Note to Cede & Co. or its registered assigns (included as Exhibit A to Exhibit 4.2.1 above).
4.3.1	Indenture, dated as of July 13, 2005, among the Company, the subsidiary guarantors party thereto and Wells Fargo Bank, National Association, with respect to the 6% Senior Subordinated Notes due 2015 (incorporated by reference to Exhibit 4.1 to the Company s Current Report on Form 8-K, filed with the SEC on July 14, 2005).
4.3.2	Form of 6% Senior Subordinated Note due 2015 (included as Exhibit A to Exhibit 4.3.1 above).
4.4.1	

	Indenture, dated as of November 16, 2005, among the Company, the subsidiary guarantors party thereto and Wells Fargo Bank, National Association with respect to Subordinated Debt Securities (incorporated by reference to Exhibit 4.1 to the Company s Current Report on Form 8-K, filed with the SEC on November 23, 2005).
4.4.2	First Supplemental Indenture, dated as of November 16, 2005, among the Company, the subsidiary guarantors party thereto and Wells Fargo Bank, National Association, with respect to the $7^{1}/4\%$ Senior Subordinated Notes due 2017 (incorporated by reference to Exhibit 4.2 to the Company s Current Report on Form 8-K, filed with the SEC on November 23, 2005).
4.4.3	Form of $7^{1}/4\%$ Senior Subordinated Note due 2017 (included as Exhibit A to Exhibit 4.4.2 above).
10.1+	2000 Incentive Stock Plan (incorporated by reference to Exhibit 4.1 to the Company s Registration Statement on Form S-8 (File No. 333-120422), filed with the SEC on November 12, 2004).

ENCORE ACQUISITION COMPANY

Exhibit No.	Description
10.2+	Employee Severance Protection Plan (incorporated by reference to Exhibit 10.1 to the Company s Quarterly Report on Form 10-Q for the quarterly period ended March 31, 2003, filed with the SEC on May 8, 2003).
10.3+	Form of Restricted Stock Award Executive (incorporated by reference to Exhibit 10.3 to the Company s Annual Report on Form 10-K for the year ended December 31, 2005).
10.4+	Form of Stock Option Agreement (Nonqualified) (incorporated by reference to Exhibit 10.4 to the Company s Annual Report on Form 10-K for the year ended December 31, 2005).
10.5+	Form of Stock Option Agreement (Incentive) (incorporated by reference to Exhibit 10.5 to the Company s Annual Report on Form 10-K for the year ended December 31, 2005).
10.6+	Form of Indemnification Agreement for directors and executive officers (incorporated by reference to Exhibit 10.6 of the Company s 2004 Annual Report on Form 10-K for the year ended December 31, 2004).
10.7	Description of Compensation Payable to Non-Management Directors (incorporated by reference to Exhibit 10.1 of the Company s Form 8-K filed with the SEC on February 22, 2006).
10.8	Amended and Restated Credit Agreement, dated August 19, 2004, among the Company, Encore Operating, L.P., Bank of America, N.A., as Administrative Agent, Fotis Capital Corp. and Wachovia Bank, N.A., as Co-Syndication Agents, BNP Paribas and Citibank, N.A., as Co-Documentary Agents and the financial institutions party thereto (incorporated by reference to Exhibit 10.1 to the Company s Current Report on Form 8-K, filed with the SEC on August 25, 2004).
10.9	First Amendment to Credit Agreement, dated April 29, 2005 (incorporated by reference to Exhibit 10.1 of the Company s Current Report on Form 8-K, filed with the SEC on May 4, 2005).
10.10	Second Amendment to Credit Agreement, dated November 14, 2005 (incorporated by reference to Exhibit 10.1 of the Company s Current Report on Form 8-K, filed with the SEC on November 18, 2005).
10.11	Third Amendment to Credit Agreement, dated December 29, 2005 (incorporated by reference to Exhibit 10.1 of the Company s Current Report on Form 8-K, filed with the SEC on January 5, 2006).
10.12	Registration Rights Agreement, dated August 18, 1998, by and among the Company and the other parties thereto (incorporated by reference to Exhibit 4.2 to the Company s

	Registration Statement on Form S-1 (File No. 333-47540), filed with the SEC on October 6, 2000).
12.1*	Statement showing computation of ratios of earnings to fixed charges.
21.1*	Subsidiaries of the Company as of February 1, 2007.
23.1*	Consent of Ernst & Young LLP.
23.2*	Consent of Miller and Lents, Ltd.
24.1*	Power of Attorney (included on the signature page of this report).
31.1*	Rule 13a-14(a)/15d-14(a) Certification (Principal Executive Officer).
31.2*	Rule 13a-14(a)/15d-14(a) Certification (Principal Financial Officer).
32.1*	Section 1350 Certification (Principal Executive Officer).
32.2*	Section 1350 Certification (Principal Financial Officer).

* Filed herewith
+ Management contract or compensatory plan, contract, or arrangement

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ENCORE ACQUISITION COMPANY
SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized.

Encore Acquisition Company

Date: February 28, 2007 By: /s/ Jon S. Brumley

Jon S. Brumley
Chief Executive Officer

KNOW ALL MEN BY THESE PRESENTS, that each individual whose signature appears below constitutes and appoints Jon S. Brumley and Robert C. Reeves, and each of them, his true and lawful attorneys-in-fact and agents with full power of substitution, for him and in his name, place and stead, in any and all capacities, to sign any and all amendments (including post-effective amendments) to this report, and to file the same, with all exhibits thereto, and all documents in connection therewith, with the SEC, granting unto said attorneys-in-fact and agents, full power and authority to do and perform each and every act and thing requisite and necessary to be done in and about the premises, as fully to all intents and purposes as he might or could do in person, hereby ratifying and confirming all that said attorneys-in-fact and agents, or his or their substitutes, may lawfully do or cause to be done by virtue hereof.

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the registrant in the capacities and on the dates indicated.

Signature	Title or Capacity	Date
/s/ I. Jon Brumley I. Jon Brumley	Chairman of the Board and Director	February 28, 2007
/s/ Jon S. Brumley Jon S. Brumley	Chief Executive Officer, President, and Director (Principal Executive Officer)	February 28, 2007
/s/ Robert C. Reeves Robert C. Reeves	Senior Vice President, Chief Financial Officer, and Treasurer (Principal Financial Officer and Principal Accounting Officer)	February 28, 2007
/s/ John A. Bailey John A. Bailey	Director	February 28, 2007
/s/ Martin C. Bowen Martin C. Bowen	Director	February 28, 2007
/s/ Ted Collins, Jr.	Director	February 28, 2007

Ted Collins, Jr.		
/s/ Ted A. Gardner	Director	February 28, 2007
Ted A. Gardner		

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ENCORE ACQUISITION COMPANY

Signature	Title or Capacity	Date
/s/ John V. Genova John V. Genova	Director	February 28, 2007
/s/ James A. Winne III James A. Winne III	Director	February 28, 2007

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