ENCORE ACQUISITION CO
Form 10-K
March 01, 2007

Table of Contents

UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549
Form 10-K

(Mark One)

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

ENCORE ACQUISITION COMPANY
INDEX

Table of Contents

ENCORE ACQUISITION COMPANY
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.

Table of Contents

ENCORE ACQUISITION COMPANY

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.

Table of Contents

ENCORE ACQUISITION COMPANY

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.

ENCORE ACQUISITION COMPANY

This Report contains forward-looking statements, which give our current expectations and forecasts of future events. The Private Securities Litigation Reform Act of 1995 provides a safe harbor for forward-looking statements made by us or on our behalf. Please read Item 1A. Risk Factors for a description of various factors that could materially affect our ability to achieve the anticipated results described in the forward-looking statements. Certain terms commonly used in the oil and natural gas industry and in this Report are defined above under the caption Glossary 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

Table of Contents

ENCORE ACQUISITION COMPANY

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 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.

Table of Contents

ENCORE ACQUISITION COMPANY

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

4

Table of Contents

ENCORE ACQUISITION COMPANY

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		

Table of Contents

ENCORE ACQUISITION COMPANY

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

Table of Contents

ENCORE ACQUISITION COMPANY

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

Table of Contents

ENCORE ACQUISITION COMPANY

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;

ENCORE ACQUISITION COMPANY

- require remedial measures to mitigate pollution from former and ongoing operations, such as requirements to close pits and plug abandoned wells;
- impose substantial liabilities for pollution resulting from operations; and
- require preparation of a Resource Management Plan, Environmental Assessment and/or an Environmental Impact Statement for operations affecting federal lands or leases.

These laws, rules, and regulations may also restrict the rate of oil and natural gas production below the rate that would otherwise be possible. The regulatory burden on the oil and natural gas industry increases the cost of doing business in the industry and consequently affects profitability. Additionally, Congress and federal and state agencies frequently revise environmental laws and regulations, and the clear trend in environmental regulation is to place more restrictions and limitations on activities that may affect the environment. Any changes that result in 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

ENCORE ACQUISITION COMPANY

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,

Table of Contents

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,

Table of Contents

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.

ENCORE ACQUISITION COMPANY

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.

Table of Contents

ENCORE ACQUISITION COMPANY

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.

Table of Contents

ENCORE ACQUISITION COMPANY

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;

Table of Contents

ENCORE ACQUISITION COMPANY

- 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

ENCORE ACQUISITION COMPANY

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.

Table of Contents

ENCORE ACQUISITION COMPANY

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

ENCORE ACQUISITION COMPANY

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;

Table of Contents

ENCORE ACQUISITION COMPANY

- 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.

ENCORE ACQUISITION COMPANY

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

ENCORE ACQUISITION COMPANY

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

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.

ENCORE ACQUISITION COMPANY

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.

ENCORE ACQUISITION COMPANY

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.

Table of Contents

ENCORE ACQUISITION COMPANY

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

Table of Contents

ENCORE ACQUISITION COMPANY

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.

ENCORE ACQUISITION COMPANY

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.

Table of Contents

ENCORE ACQUISITION COMPANY

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.

Table of Contents

ENCORE ACQUISITION COMPANY
PART II

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

Our common stock, $0.01 par value, is listed on the NYSE under the symbol EAC . The following table sets forth 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.

Table of Contents

ENCORE ACQUISITION COMPANY

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

Table of Contents

ENCORE ACQUISITION COMPANY

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				

Table of Contents

ENCORE ACQUISITION COMPANY

	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.

Table of Contents

ENCORE ACQUISITION COMPANY

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;

Table of Contents

ENCORE ACQUISITION COMPANY

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.

ENCORE ACQUISITION COMPANY

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 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.

Table of Contents

ENCORE ACQUISITION COMPANY

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.

Table of Contents

ENCORE ACQUISITION COMPANY

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	Year Ended December 31, 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)%*

Table of Contents

ENCORE ACQUISITION COMPANY

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

Table of Contents

ENCORE ACQUISITION COMPANY

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.

Table of Contents

ENCORE ACQUISITION COMPANY

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.

ENCORE ACQUISITION COMPANY

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

ENCORE ACQUISITION COMPANY

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,		*Increase/*
	2006	**2005**	**(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.

Table of Contents

ENCORE ACQUISITION COMPANY

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	Year Ended December 31, 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^{3}/8% Senior Subordinated Notes (the 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 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^{1}/4% Senior Subordinated Notes (the 7^{1}/4% Notes) in November 2005, $300 million of 6% Notes in July 2005, and $150 million of 6^{1}/4% Senior Subordinated Notes (the 6^{1}/4% Notes) in April 2004. We also redeemed all $150 million of 8^{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	Year Ended December 31, 2005	*Increase/* (Decrease)
	(In thousands)		
8^{3}/8% Notes	$	$ 7,852	$ (7,852)
6^{1}/4% Notes	9,684	9,375	309
6% Notes	18,418	8,437	9,981
7^{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

ENCORE ACQUISITION COMPANY

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%*

ENCORE ACQUISITION COMPANY

	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.

Table of Contents

ENCORE ACQUISITION COMPANY

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%*

48

ENCORE ACQUISITION COMPANY

	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 t