ENCORE ACQUISITION CO
Form 10-K
March 10, 2005

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

þ **ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**

For the fiscal year ended December 31, 2004

Encore Acquisition Company
(Exact name of registrant as specified in its charter)

Delaware	**001-16295**	**75-2759650**
(State or other jurisdiction of incorporation)	*(Commission File Number)*	*(IRS 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 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 an accelerated filer (as defined in Exchange Act Rule 12b-2) Yes þ No o

Aggregate market value of the voting and non-voting common stock held by non-affiliates of the Registrant as of June 30, 2004 (the last business day of Registrant s most recently completed second fiscal quarter)	$	848,026,610
Number of shares of Common Stock, $0.01 par value, outstanding as of February 28, 2005		32,861,474

DOCUMENTS INCORPORATED BY REFERENCE

Parts of the definitive proxy statement for the Registrant s 2005 annual meeting of stockholders are incorporated by reference into Part III of this report on Form 10-K.

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This annual report on Form 10-K (the 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 or on behalf of Encore Acquisition Company or its subsidiaries. See Item 7. Management s Discussion and Analysis of Financial Condition and Results of Operation for a description of various factors that could materially affect the ability of Encore Acquisition Company 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 at the end of Item 7A, beginning on page 50, 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 Encore Acquisition Company.

PART I

Items 1 and 2. *Business and Properties*

General

Our Business. We are a growing independent energy company engaged in the acquisition, development, exploitation, exploration, and production of onshore North American oil and natural gas reserves. Since our inception in 1998, we have sought to acquire high quality assets with potential for upside through low-risk development drilling projects. 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 Mid-Continent area, which includes the Arkoma and Anadarko Basins of Oklahoma, the ArkLaTx region of northern Louisiana and east Texas, and the Barnett Shale of north Texas; and the Rockies, which includes non-CCA assets in the Williston and Powder River Basins of Montana, and the Paradox Basin of southeastern Utah. For the three years ended December 31, 2004, we have invested $373.5 million in acquiring producing oil and natural gas properties, and we have invested an incremental $336.9 million on development and exploitation of our properties.

Most Valuable Asset. The CCA represented 66% of our total proved reserves as of December 31, 2004. 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.

Recent Acquisitions.

<u>Cortez Oil & Gas, Inc.</u> On April 14, 2004, we purchased all of the outstanding capital stock of Cortez Oil & Gas, Inc. (Cortez), a privately held, independent oil and natural gas company, for a total purchase price of $127.0 million, which includes cash paid to Cortez former shareholders of $85.8 million, the repayment of $39.4 million of Cortez debt, and transaction costs incurred of $1.8 million.

The acquired oil and natural gas properties are located primarily in the CCA of Montana, the Permian Basin of West Texas and Southeastern New Mexico and in the Mid-Continent area, including the Anadarko and Arkoma Basins of Oklahoma and the Barnett Shale north of Fort Worth, Texas. Cortez operating results are included in our Consolidated Statement of Operations for the period from April through December 2004.

<u>Overton.</u> On June 17, 2004, we completed the acquisition of natural gas producing properties and undeveloped leases in the Overton Field located in Smith County, Texas for $83.1 million. The Overton Field assets are in the same core area as our interests in Elm Grove Field and have similar geology. Operating results for the Overton Field properties are included in our Consolidated Statement of Operations for the period from July through December 2004.

We identified over 100 drilling locations in the Travis Peak and Cotton Valley formations on the acreage in the Overton Field at the time of the acquisition. Subsequent to the close of the acquisition, we

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have implemented an active drilling program to develop the field. The properties produce primarily from multiple tight sandstone reservoirs in the Travis Peak and Cotton Valley formations at depths ranging between 8,000 and 11,500 feet. The production is 94% natural gas and the properties are 100% operated.

Drilling. In 2004, we drilled 168 gross operated productive wells and participated in drilling another 67 gross non-operated productive wells for a total of 235 gross productive wells for the year. On a net basis, we drilled 156.4 operated productive wells and participated in 8.8 non-operated productive wells in 2004. Out of the 168 (156.4 net) operated productive wells 12 (11.5 net) wells were service wells. We also drilled 5 (4.5 net) non-productive wells in 2004 of which 4 (3.9 net) were exploratory wells.

Oil and Natural Gas Production and Reserves. In 2004, our reserve growth was achieved through acquisitions, high-pressure air injection and drilling wells. We continue to pursue high-quality assets and to seek to replenish our drilling inventory through acquisitions, drilling extension wells and leasing acreage on which we can prospect.

The following table sets forth our total proved reserves, average daily production and reserve-to-production ratio, or R/P index, in our principal areas of operation as of December 31, 2004 and for the year then ended.

	Proved Reserves at December 31, 2004 (MBOE)	Percent of Total	Average Daily Production for 2004 (BOE/d)	Percent of Total	Average Daily Production Q4 2004(2) (BOE/d)	Percent of Total	Pro-Forma R/P Index(2)
Cedar Creek Anticline(1)	113,873	66%	13,660	55%	13,518	52%	23.0
Permian Basin	29,336	17%	5,368	22%	6,023	23%	13.3
Mid-Continent	22,835	13%	3,359	14%	4,441	17%	14.1
Rockies	7,009	4%	2,278	9%	2,114	8%	9.1
Total	173,053	100%	24,665	100%	26,096	100%	18.1

(1) Our CCA properties, which produce mainly from porous dolomites drilled on 40 to 80 acre spacing intervals, have longer reserve lives than our other properties because the low permeability level encountered within those producing intervals require a longer time to produce the reserves in place. This results in a lower production decline rate.

(2) R/ P index is a ratio used by management and the oil and natural gas industry to analyze the length of time the Company s reserves can generate cash flows at current production levels. This calculation is derived by dividing our total proved reserves into our production. In calculating the pro forma R/P index, we annualized our fourth quarter 2004 production because it includes production from both the Cortez and Overton acquisitions for the entire quarter. We believe this approach more accurately reflects our R/P index. Based on full year 2004 production, our R/P index was 22.8 for Cedar Creek Anticline, 14.9 for Permian Basin, 18.6 for Mid-Continent, 8.4 for Rockies, and 19.2 for all properties.

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During 2004, we added 41.2 MMBOE of oil and natural gas reserves, which replaced 456% of the 9.0 MMBOE we produced in 2004. Our three year average reserve replacement ratio is 381%. The following table sets forth our calculation of our 2004, 2003, 2002, and three year average reserve replacement ratios (in thousands of BOE except percentages):

	Year Ended December 31,			
	2004	2003	2002	Three Year Average
Acquisition Reserve Replacement Ratio				
Changes in Proved Reserves:				
Acquisitions of minerals-in-place	22,239	6,257	15,461	43,957
Divided by:				
Production	9,027	8,110	7,399	24,536
Acquisition reserve replacement ratio	246%	77%	209%	179%
Development Reserve Replacement Ratio				
Changes in Proved Reserves:				
Extensions and discoveries	8,768	5,182	13,546	27,496
Improved recovery	11,812	12,744		24,556
Revisions of estimates	(1,629)	(3,493)	2,719	(2,403)
Total development program	18,951	14,433	16,265	49,649
Divided by:				
Production	9,027	8,110	7,399	24,536
Development reserve replacement ratio	210%	178%	220%	202%
Total Reserve Replacement Ratio				
Changes in Proved Reserves:				
Acquisitions of minerals-in-place	22,239	6,257	15,461	43,957
Extensions and discoveries	8,768	5,182	13,546	27,496
Improved recovery	11,812	12,744		24,556
Revisions of estimates	(1,629)	(3,493)	2,719	(2,403)
Total reserve additions	41,190	20,690	31,726	93,606
Divided by:				
Production	9,027	8,110	7,399	24,536
Total reserve replacement ratio	456%	255%	429%	381%

Business Strategies

Our primary business objective is to maximize internally generated cash flow and shareholder value by executing the following strategies:

Maintain an active development drilling 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 development drilling, workovers, waterflood enhancements, recompletions, and tertiary projects. Our plan is to maintain an inventory of exploitation and development projects that provide us ongoing drilling activity. Each year, we budget a portion of internally generated cash flow to secondary and tertiary recovery projects whose results will not be seen until future years.

Maximize existing reserves and production through high-pressure air injection. In addition to conventional development drilling, we utilize high-pressure air injection techniques on certain properties to enhance our growth. High-pressure air injection (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. We believe that the HPAI programs on our CCA properties will generate a higher rate of return than other tertiary processes and can be applied throughout our CCA properties.

Expand our reserves, production, and drilling inventory through a disciplined acquisition program. We will continue to pursue acquisitions of properties with similar upside potential to our current portfolio of producing properties. Using the experience of our management team, we have developed and refined an acquisition program designed to increase our reserves and to complement our core properties, while providing upside potential. 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 in 2005 with the same disciplined commitment to acquire assets that fit our portfolio and create value for our shareholders.

Explore for reserves. With the current high-priced commodity environment, we believe modest exploration programs can provide a rate of return comparable or superior 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 are expected to set up multi-well exploitation projects if successful.

Operate in a cost effective, efficient, and safe manner. As of December 31, 2004, we operated properties representing approximately 85% 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. Our primary challenge is to generate superior rates of return on our investments in a volatile commodity pricing environment, while replenishing our drilling inventory. Changing commodity prices 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 the changing commodity price risk, we face strong competition from independents and major oil companies. For more information on the challenges to implementing our strategy and achieving our goals, please read Factors That May Affect Future Results and Financial Condition beginning on page 42.

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Business Activities

The following table sets forth the net production, proved reserves quantities, and PV-10 values of our properties in our principal areas of operation:

Properties Principal Areas of Operations

	Net Production 2004				Proved Reserve Quantities at December 31, 2004			PV-10 at December 31, 2004	
	Oil (MBbls)	Natural Gas (MMcf)	Total (MBOE)	Percent	Oil (MBbls)	Natural Gas (MMcf)	Total (MBOE)	Amount(1)	Percent
								(In thousands)	
Cedar Creek Anticline	4,795	1,228	4,999	55%	110,802	18,426	113,873	$ 977,136	60%
Permian Basin	1,049	5,490	1,965	22%	15,693	81,858	29,336	340,659	21%
Mid-Continent	61	7,011	1,229	14%	1,283	129,310	22,835	226,472	14%
Rockies	774	360	834	9%	6,270	4,436	7,009	80,202	5%
Total	6,679	14,089	9,027	100%	134,048	234,030	173,053	$ 1,624,469	100%

(1) 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%. Giving effect to hedging transactions and using prices as of the date of estimation, our PV-10 value would have been decreased by $58.8 million at December 31, 2004. The Standardized Measure at December 31, 2004 is $1.2 billion. Standardized Measure differs from PV-10 by $458.9 million because Standardized Measure includes the effect of asset retirement obligations and future income taxes.

Operations

We act as operator of properties representing approximately 85% of our proved reserves at December 31, 2004. As operator, we are able to better control expenses, capital allocation, and the timing of exploitation and development activities of these 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 the costs of operating, exploiting, and developing them. See Properties Nature of Our Ownership Interests on page 13. During the years ended December 31, 2004, 2003, and 2002 our approximate costs for development activities on non-operated properties were $10.9 million, $5.4 million, and $3.4 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.

Proved Reserves

Proved developed reserves are proved reserves that are expected to be recovered from existing wells with existing equipment and operating methods. 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 also include unrealized production response from fluid injection and other improved recovery techniques, such as high-pressure air injection, where such techniques have been proven effective by actual tests in the area and in the same reservoir.

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The following table sets forth estimated period end proved reserves for the periods indicated as estimated by Miller and Lents, Ltd., independent petroleum engineers (in thousands except per Bbl and per Mcf amounts):

	As of December 31,		
	2004	2003	2002
Oil (Bbls)			
Developed	97,114	92,377	93,945
Undeveloped	36,934	25,355	17,729
Total	134,048	117,732	111,674
Natural Gas (Mcf)			
Developed	156,919	104,767	82,217
Undeveloped	77,111	34,183	17,601
Total	234,030	138,950	99,818
Combined (BOE)			
Developed	123,267	109,838	107,648
Undeveloped	49,786	31,052	20,662
Total(1)	173,053	140,890	128,310
PV-10(2)			
Developed	$ 1,296,201	$ 844,873	$ 732,823
Undeveloped	328,268	176,201	132,281
Total	$ 1,624,469	$ 1,021,074	$ 865,104
Standardized Measure(3)	$ 1,165,619	$ 736,939	$ 624,718
Reserve price assumptions			
Oil ($/Bbl)	$ 43.46	$ 32.55	$ 31.20
Natural gas ($/Mcf)	6.19	5.83	4.79

(1) Volumetric reserves attributed to the net profits interests in our CCA properties were 24,774 MBOE, 20,623 MBOE, and 16,262 MBOE, respectively, at December 31, 2004, 2003, and 2002. See Net Profits Interests on page 14. The volumes attributed to the net profits interests, which reduce our reserves on a BOE-for-BOE basis, will fluctuate from period to period primarily based on commodity prices and the level of planned development expenditures.

(2) The pretax present value of estimated future revenues to be generated from the production of proved reserves; net of estimated future 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%. Giving effect to hedging transactions and using prices as of the date of estimation, our PV-10 value would have been $1.6 billion at December 31, 2004, $997.2 million at December 31, 2003, and $860.6 million at December 31, 2002.

(3) Estimated future cash inflows to be generated from the production and sale of proved oil and natural gas reserves, net of estimated future production and development costs, asset retirement obligations and future income tax expenses, discounted at 10% per annum to reflect the timing of future cash flows. Standardized Measure differs from PV-10 by $458.9 million because Standardized Measure includes the effect of asset retirement obligations and future income taxes.

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There are numerous uncertainties inherent in estimating quantities of proved reserves and in projecting future rates of production and timing of exploitation expenditures. The data in the above table represents estimates only. Oil and natural gas reserve engineering is inherently a subjective process of estimating underground accumulations of oil and natural gas that cannot be measured exactly, and estimates of other engineers might differ materially from those shown above. The accuracy of any reserve estimate is a function of the quality of available data and engineering and geological interpretation and judgment. Results of drilling, testing, and production, after the date of the estimate, may justify revisions. Accordingly, reserve estimates may vary significantly from the quantities of oil and natural gas that are ultimately recovered.

Future prices received for production and future costs may vary, perhaps significantly, from the prices and costs assumed for purposes of these estimates. The PV-10 reserve value shown should not be construed as the current market value of the reserves. The 10% discount factor used to calculate present value, which is mandated by Statement of Financial Accounting Standard No. 69, Disclosures about Oil and Gas Producing Activities, is not necessarily the most appropriate discount rate. The present value, no matter what discount rate is used, is materially affected by assumptions as to timing of future production, which may prove to be inaccurate. For properties that we operate, future production expenses exclude our share of contractual overhead charges. In addition, the calculation of estimated future costs does not take into account the effect of various cash outlays.

During the calendar year 2004, we filed estimates of oil and natural gas reserves at December 31, 2003 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, Ltd., who are independent petroleum engineers.

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 each of the periods indicated:

	Year Ended December 31,		
	2004	2003	2002
Production:			
Oil (MBbls)	6,679	6,601	6,037
Natural gas (MMcf)	14,089	9,051	8,175
Combined (MBOE)	9,027	8,110	7,399
Average Daily Production:			
Oil (Bbls/d)	18,249	18,085	16,540
Natural gas (Mcf/d)	38,493	24,798	22,397
Combined (BOE/d)	24,665	22,218	20,273
Average Prices:			
Oil (per Bbl)	$ 33.04	$ 26.72	$ 22.34
Natural gas (per Mcf)	5.53	4.83	3.16
Combined (per BOE)	33.07	27.14	21.72
Average Costs per BOE:			
Lease operations expense	$ 5.22	$ 4.67	$ 4.15
Production, ad valorem, and severance taxes	3.36	2.71	2.12
Depletion, depreciation, and amortization	5.38	4.13	4.67
General and administrative (excluding non-cash stock based compensation)	1.22	1.07	0.83

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Producing Wells

The following table sets forth information at December 31, 2004 relating to the producing wells in which we owned a working interest as of that date. We also held royalty interests in units and acreage beyond the wells in which we have a working interest. 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.

	Oil Wells			Natural Gas Wells		
	Gross Wells	Net Wells	Average Working Interest	Gross Wells	Net Wells	Average Working Interest
Cedar Creek Anticline	700	614.5	88%	13	4.6	35%
Permian Basin	1,416	364.8	26%	444	177.1	40%
Rockies	546	299.3	55%			0%
Mid-Continent	112	14.4	13%	524	103.3	20%
Total	2,774(1)	1,293.0	47%	981(1)	285.0	29%

(1) Our total wells include 1,595 operated wells and 2,160 non-operated wells. At December 31, 2004, 13 of our wells have multiple completions.

Acreage

The following table sets forth information at December 31, 2004 relating to acreage held by us. 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 is concentrated in our Montana properties, which represents 87% of our total undeveloped acreage. These leases expire at various dates ranging from 2005 to 2017, with leases representing $0.3 million of cost set to expire in 2005 if not developed.

	Gross Acreage	Net Acreage
Developed acreage	350,489	179,387
Undeveloped acreage	562,241	398,042
Total	912,730	577,429

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Drilling Results

The following table sets forth information with respect to wells drilled during the periods indicated. The information should not be considered indicative of future performance, nor should a correlation be assumed between the number of productive wells drilled, quantities of reserves found, or economic value. Development wells are wells drilled within the proved area of an oil or gas reservoir to the depth of a stratigraphic horizon known to be productive. Exploratory wells are wells drilled to find and produce oil or gas in an unproved area, to find a new reservoir in a field previously found to be productive of oil or gas in another reservoir, or to extend a known reservoir. Productive wells are those that produce commercial quantities of hydrocarbons, exclusive of their capacity to produce at a reasonable rate of return.

	Year Ended December 31,					
	2004		2003		2002	
	Gross	Net	Gross	Net	Gross	Net
Development Wells						
Productive	203	135.5	137	103.0	109	95.3
Non-productive	1	0.6	1	0.7		
Total development	204	136.1	138	103.7	109	95.3
Exploratory Wells						
Productive	32	29.7				
Non-productive	4	3.9				
Total development	36	33.6				
All Wells Drilled						
Total productive wells drilled	235	165.2	137	103.0	109	95.3
Total dry holes drilled	5	4.5	1	0.7		
Grand total	240	169.7	138	103.7	109	95.3

Present Activities

As of December 31, 2004, we had a total of 14 gross (7.9 net) wells that had been spud and were in varying stages of drilling operations, of which 3 gross (2.2 net) wells were exploratory wells. Also, there were 34 gross (27.0 net) wells that had reached total depth and were in varying stages of completion pending first production, of which 12 gross (11.6 net) wells were exploratory wells.

We are implementing the expansion of the HPAI program to the entire north end of the Pennel unit of the Cedar Creek Anticline, which we expect to complete by the end of 2005. We plan to begin high-pressure air injection in the second quarter of 2005.

We have implemented the first two phases of the HPAI program for the Little Beaver unit in the Cedar Creek Anticline. Air injection has been ongoing since December 2003, and the reservoir is pressuring up as expected.

Delivery Commitments and Marketing

Consistent with industry practices, 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 storage facilities. While we typically market our oil and gas production for a term of a year or less, we entered into an agreement in 2004 to sell at least 2,500 barrels of oil per day at a floating market price through 2009.

For the fiscal year 2004, our largest purchasers included Shell and ConocoPhillips, which respectively accounted for 29% and 27% of total oil and natural gas sales. 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 is of the opinion 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 sale of our CCA oil production is dependent on transportation to markets through Butte Pipeline to Guernsey, Wyoming. Any restrictions on the available capacity for us to transport oil in this pipeline could have a material adverse effect on our price we receive and our oil revenues.

Competition

We compete with major and independent oil and natural gas companies. Some of our competitors have substantially greater financial and other resources than we do. In addition, larger competitors may be able to absorb the burden of any changes in federal, state, provincial, and local laws and regulations more easily than we can, adversely affecting our competitive position. Our competitors may be able to pay more for 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 we can. Further, these companies may enjoy technological advantages and may be able to implement new technologies more rapidly than we can. Our ability to acquire additional properties in the future will depend upon our ability to conduct efficient operations, evaluate and select suitable properties, implement advanced technologies, and consummate transactions in this highly competitive environment.

Federal and State Regulations

Compliance with applicable federal and state regulations is often difficult and costly, and non-compliance may result in substantial penalties. The following are some specific regulations that may affect us. We cannot predict the impact of these or future legislative or regulatory initiatives.

Federal Regulation of Natural Gas. The interstate transportation and sale for resale of natural gas is subject to federal regulation, including transportation rates and various other matters, by the Federal Energy Regulatory Commission (FERC). Federal wellhead price controls on all domestic natural gas were terminated on January 1, 1992 and none of our natural gas sales are currently subject to FERC regulation. We cannot predict the impact of future government regulation on any natural gas operations.

Although FERC s regulations should generally facilitate the transportation of natural gas produced from our properties and the direct access to end-user markets, the future impact of these regulations on marketing our production or on our natural gas transportation business cannot be predicted. We do not believe, however, that we will be affected differently than competing producers and marketers.

Federal Regulation of Oil. Sales of crude oil, condensate and natural gas liquids are not currently regulated and are made at market prices. The net price received from the sale of these products is affected by market transportation costs. A significant part of our oil production is transported by pipeline. Under rules adopted by FERC effective January 1995, interstate oil pipelines can change rates based on an inflation index, though other rate mechanisms may be used in specific circumstances. The United States Court of Appeals upheld FERC s orders in 1996. These rules have had little effect on our oil transportation cost.

State Regulation. Oil and natural gas operations are subject to various types of regulation at the state and local levels. Such regulation includes requirements for drilling permits, the method of developing new fields, the spacing and operations of wells, and waste prevention. The production rate may be regulated and the maximum daily production allowable from oil and natural gas wells may be established on a market demand or conservation basis. These regulations may limit production by well and the number of wells that can be drilled.

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

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Environmental Regulations. Various federal, state and local laws regulating the discharge of materials into the environment, or otherwise relating to the protection of the environment, directly impact oil and natural gas exploration, development and production operations, and consequently may impact our operations and costs. Management believes that we are in substantial compliance with applicable environmental laws and regulations. To date, we have not expended any material amounts to comply with such regulations, and we do not currently anticipate that future compliance will have a materially adverse effect on our consolidated financial position, cash flows, or results of operations.

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 164 employees as of December 31, 2004, 62 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

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 as soon as reasonably practicable after we electronically file such material with or furnish such material to the SEC. In addition, the public may read and copy any materials that we file with the SEC at the SEC s Public Reference Room at 450 Fifth Street, NW, Washington, DC 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 senior financial officers. 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 2004, we submitted to the NYSE the CEO certification required by Section 303A.12(a) of the NYSE s Listed Company Manual. In 2005, we expect to submit this certification to the NYSE after the annual meeting of stockholders.

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Our board of directors currently has three standing committees: (1) audit, (2) compensation, and (3) nominating and corporate governance. The charters of our board of director 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.

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

Properties

Nature of Our Ownership Interests

We own interests in oil and natural gas properties located in four core areas: the CCA in the Williston Basin of Montana and North Dakota; the Permian Basin of West Texas and Southeastern New Mexico; the Mid-Continent area, which includes the Arkoma and Anadarko Basins of Oklahoma, the ArkLaTx region of northern Louisiana and east Texas, and the Barnett Shale of north Texas; and the Rockies, which includes non-CCA assets in the Williston and Powder River Basins of Montana, and the Paradox Basin of southeastern Utah. Substantially all of our PV-10 reserve value at December 31, 2004 was attributable to working interests in oil and natural gas properties. A working interest in an oil and natural gas lease requires us to pay our proportionate share of the costs of drilling and production.

Cedar Creek Anticline 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. The most recent addition to our CCA holdings was 37 wells acquired in the Cortez acquisition in April 2004. Presently, we operate approximately 99.4% of our CCA properties with an average working interest of approximately 87.4%. The average daily production from our CCA properties during 2004 was 13,660 BOE per day.

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 feet and 9,000 feet.

Since taking over operations, along with subsequent additional acquired interests, we have increased production by 73.2% on the CCA from 7,807 BOE per day (average for June 1999) to 13,518 BOE per day (average for the fourth quarter 2004). We have accomplished ongoing production growth through a combination of:

- additional acquisition of interests;
- detailed attention to the existing wellbores;
- the addition of strategically positioned new horizontal and vertical wellbores;
- the application of horizontal re-entry drilling in existing wellbores;
- waterflood enhancements; and
- implementation of our high-pressure air injection program.

In 2004, we drilled 82 gross wells on the CCA, of which 46 were horizontal re-entry wells that reestablished production from non-producing wells, added additional barrels from existing producing wells and serve as injection wells for secondary and tertiary recovery projects. Including our HPAI project, we incurred $116.5 million and $77.6 million of capital projects on the CCA during 2004 and 2003, respectively.

Our outlook for sustained production growth on the CCA remains strong. We plan to continue the development of the reserve base through currently identified opportunities and future opportunities resulting from knowledge gained through continued study and ongoing drilling and exploitation efforts on these properties. We believe that HPAI continues to be our most significant source of sustained production growth on the CCA.

The CCA represents 66% of our total proved reserves as of December 31, 2004. The CCA represents our most valuable asset today and in the foreseeable future. A large portion of our future success revolves around future conventional exploitation, production, and success of HPAI projects on these properties.

High-pressure air injection. In 2004 we continued our high-pressure air injection program at the CCA. High-pressure air injection is a tertiary recovery technique that involves using compressors to inject air into oil and natural gas formations in order to displace remaining resident hydrocarbons and force them under pressure to a common lifting point for production.

In 2002 we initiated a HPAI project that injects air into the Red River U4 zone in the Pennel unit of the CCA. The Red River U4 zone is the same zone where high-pressure air injection has been successfully implemented by other operators in adjacent areas on the CCA. We have seen positive results from this high-pressure air injection project at Pennel. Based on these results, we are in the process of expanding high pressure air injection to other areas in the CCA. We believe that high-pressure air injection technology can be applied throughout the CCA and that it may yield significant new reserves. We believe that the high-pressure air injection will generate a higher rate of return than other tertiary processes on the CCA.

The Phase I project at Pennel continues to perform well with production uplift on target with our original projection. In addition to the 0.7 million BOE of reserves booked in Pennel by December 31 2003, we added 6.1 million BOE of reserves in the Phase II HPAI area at Pennel in 2004. We expect to begin injecting air in the Phase II area during the first half of 2005. Phase II implementation is anticipated to be complete by the end of 2005. The Pennel project will receive the majority of the total $26.0 million budgeted for high-pressure air injection capital in 2005.

In 2003, we established a HPAI project in the Little Beaver unit of the CCA. We negotiated a compression services agreement from an offset operator to provide high-pressure air for the project. This agreement allowed us to install a high-pressure air injection project in less than one year. In 2003, we added 12.2 million BOE of reserves for the project. In 2004, we added an additional 3.0 million BOE of HPAI reserves for the Little Beaver unit because we expanded the scope of the project. Air injection has been ongoing since December 2003, and the reservoir is pressuring up as expected. The project is on schedule, and initial production uplift is expected by mid-2005.

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 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. We believe these zones can be most economically evaluated for HPAI opportunities after assessing HPAI in the Red River U4 zone.

Net Profits Interests. A major portion of our acreage position in the CCA is subject to net profits interests (NPI) ranging from 1% to 50%. The holders of these net profits interests are entitled to receive a fixed percentage of the cash flow remaining after specified costs have been subtracted from net revenue. The net profits calculations are contractually defined, but in general, net profits are determined after considering operating expense, overhead expense, interest expense, and drilling costs. The amounts of reserves and production calculated to be attributable to these net profits interests are deducted from our reserves and production data, and our revenues are reported net of NPI payments. The reserves and production that are attributed to the NPIs are calculated by dividing estimated future NPI payments (in the case of reserves) or prior period actual NPI payments (in the case of production) by the commodity prices current at the determination date. Fluctuations in commodity prices and the levels of development

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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 the years ended December 31, 2004, 2003, and 2002, we reduced revenue for the payments of the net profits interests by $12.6 million, $5.8 million, and $2.0 million, respectively.

Permian Basin Properties West Texas and New Mexico

Our Permian Basin properties include sixteen operated fields including East Cowden Grayburg Unit, Fuhrman-Nix, Henderson, Sand Hills and others; and sixteen non-operated fields including Indian Basin, North Cowden, Ozona, Yates, and others. Production from the Central Permian comes from multiple reservoirs including the Grayburg, San Andres, Glorieta, Tubb, 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 2004, we drilled 76 wells on the Permian properties primarily in the Sand Hills, Furhman-Nix, and Ozona fields. We invested approximately $32.4 million of development capital on our Permian properties. Average daily production in 2004 was 5,368 BOE per day. We believe these properties will be an area of growth over the next several years.

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 gas, and to a lesser extent oil, from various horizons. We also have operated interests in properties producing from the Barnett Shale in north Texas, and interests in properties in the Hugoton Basin in Kansas. During 2004, we invested $11.9 million of development capital in these properties. Average production in the fourth quarter of 2004 was 11,284 Mcfe per day.

ArkLaTx North Louisiana and East Texas

The ArkLaTx properties consist of operated working interests, non-operated working interests, and undeveloped leases acquired in the Elm Grove and Overton acquisitions. For the fourth quarter of 2004, the average daily production for the properties was 15,366 Mcfe per day. We invested approximately $20.9 million of capital to develop these properties during 2004. We believe these properties are an area of growth for us.

The Elm Grove properties were purchased on July 31, 2003 at a cost of $54.6 million. Subsequent to the initial acquisition, we purchased additional interests in the properties. Our interests are located in the Elm Grove Field in Bossier Parish, Louisiana. The acquired properties include non-operated working interests ranging from 1% to 47% across 1,800 net acres in 15 sections.

On June 17, 2004, we completed the acquisition of natural gas producing properties and undeveloped leases in the Overton Field located in Smith County, Texas for $83.1 million. The Overton properties have a larger proportion of proved undeveloped reserves than most of our historical acquisitions. 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 Travis Peak and Lower Cotton Valley formations at depths ranging between 8,000 and 11,500 feet. The production is 94% natural gas and the properties are 100% operated by us. We identified over 100 drilling locations in the Travis Peak and Lower Cotton Valley formations on the acreage in Overton Field at the time of the acquisition. Subsequent to the close of the acquisition, we have implemented an active drilling program to develop the field.

Rocky Mountain Properties North Dakota, Montana, and Utah

Lodgepole North Dakota

The Lodgepole properties consist of working and overriding royalty interests in several geographically concentrated fields. The Lodgepole properties are located in the Williston Basin in western North Dakota near the town of Dickinson, approximately 120 miles from our CCA properties. The Lodgepole properties produce exclusively from the Mississippian-aged Lodgepole Formation, and the Eland Unit is the largest accumulation in the trend. The average production from the Lodgepole properties was 1,224 BOE per day for 2004. In 2004, we invested an insignificant amount of capital in the Lodgepole properties.

The Lodgepole properties produce from reefs with high permeability and thick oil columns. The prolific nature of these reservoirs makes future engineering estimates related to ultimate recovery of reserves inherently difficult to determine. If the properties performance varies significantly from the Miller and Lents, Ltd. estimates of reserves, then our future cash flows could be affected in 2005 and a few years beyond.

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% working interest. The shallow (less than 5,000 feet) Cretaceous-aged Muddy Sandstone reservoir produces 100% oil. We invested $0.7 million of capital in these properties in 2004. The average daily production from the Bell Creek properties was 355 BOE per day during 2004. In the fall of 2005, we intend to initiate a small field test of new technology called Microbial Enhanced Oil Recovery (MEOR) in conjunction with the State of Montana, MSE Technology Applications Center for Innovations and Montana Tech. This process may enhance oil production by creating a natural Bio-film which diverts injected water towards un-swept oil.

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 operated by ExxonMobil and the Aneth Unit operated by Resolute Natural Resources Company. Our average net production from the properties for 2004 was approximately 699 BOE per day. We believe these properties have potential horizontal redevelopment, secondary development, and tertiary recovery potential. Our development capital for these properties was $0.1 million during 2004.

Shallow Gas Montana

We have begun a project to explore for natural gas in the shallow zones of our acreage in north central Montana. The primary producing horizon in this area is the Eagle Sandstone, which produces from reservoir depths between 800 feet and 1,200 feet. This Eagle Sandstone has produced large quantities of gas to date from numerous fields across northern Montana. We invested $4.3 million in capital during 2004 to drill a total of 11 wells. Three of the wells were completed as productive and began producing natural gas in early 2005 for a capital investment of $0.8 million, five wells are being evaluated for completion, and three wells were expensed as dry holes in 2004 for a total cost of $0.8 million.

All wells that we drilled in this area in 2004, and any that we may drill in the future, will likely be classified as exploratory in nature. As such, the success rate of these wells will be lower than our historical average. Additionally, there can be no guarantee that reserves will be found in a sufficient quantity as to make them economically producible. If reserves are not found in a quantity that would make them economically producible, all costs to drill the well, as well as any related undeveloped leasehold costs associated with the lease on which the well was drilled, would be expensed in the period in which the determination was made.

Title to Properties

We believe that our title to our oil and natural gas properties is good and defensible in accordance with standards generally accepted in the oil and natural gas industry.

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

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

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

ITEM 3. *Legal Proceedings*

We are not currently a party to any material legal proceeding of which we are aware.

ITEM 4. *Submission of Matters to a Vote of Security Holders*

There were no matters submitted to stockholders during the quarter ended December 31, 2004.

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PART II

Item 5. *Market for Registrant s Common Equity, Related Stockholder Matters and Issuer Purchases of Equity Securities*

Our common stock, $0.01 par value, is listed on the NYSE under the symbol EAC. The following table sets forth quarterly high and low sales prices of our common stock for each quarterly period of 2004 and 2003:

	High	Low
2004		
Quarter ended December 31	$ 36.88	$ 30.56
Quarter ended September 30	34.75	25.49
Quarter ended June 30	31.50	24.81
Quarter ended March 31	28.85	23.65
2003		
Quarter ended December 31	$ 25.28	$ 19.60
Quarter ended September 30	22.15	17.80
Quarter ended June 30	20.01	17.00
Quarter ended March 31	19.35	16.63

On February 28, 2005, we had approximately 220 shareholders of record.

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 our board of directors 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 credit agreement and the indentures governing our $8^{3}/8$% and $6^{1}/4$% notes. Future debt agreements may also restrict our ability to pay dividends.

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Item 6. ***Selected Financial Data***

The following selected consolidated financial data should be read in conjunction with Item 7. Management s Discussion and Analysis of Financial Condition and Results of Operations and Item 8. Financial Statements and Supplementary Data (in thousands except per share and per unit data):

	Year Ended December 31,				
	2004	2003	2002	2001	2000
Consolidated Statement of Operations Data:					
Revenues(1):					
Oil	$ 220,649	$ 176,351	$ 134,854	$ 105,768	$ 92,441
Natural gas	77,884	43,745	25,838	30,149	16,509
Total revenues	$ 298,533	$ 220,096	$ 160,692	$ 135,917	$ 108,950
Net income (loss)	$ 82,147	$ 63,641(2)	$ 37,685	$ 16,179(3)	$ (2,135)(4)
Net income (loss) per common share:					
Basic	$ 2.62	$ 2.11	$ 1.25	$ 0.56	$ (0.09)
Diluted	2.58	2.10	1.25	0.56	(0.09)
Weighted average number of common shares outstanding:					
Basic	31,393	30,102	30,031	28,718	22,806
Diluted	31,825	30,333	30,161	28,723	22,806
Consolidated Statement of Cash Flows Data:					
Cash provided by (used by):					
Operating activities	$ 171,821	$ 123,818	$ 91,509	$ 80,212	$ 44,508
Investing activities	(433,470)	(153,747)	(159,316)	(89,583)	(99,236)
Financing activities	262,321	17,303	80,749	8,610	49,107
Production:					
Oil (Bbls)	6,679	6,601	6,037	4,935	3,961
Natural gas (Mcf)	14,089	9,051	8,175	8,078	4,303
Combined (BOE)	9,027	8,110	7,399	6,281	4,678
Average Sales Price:					
Oil ($/Bbl)	$ 33.04	$ 26.72	$ 22.34	$ 21.43	$ 23.34
Natural gas ($/Mcf)	5.53	4.83	3.16	3.73	3.84
Combined ($/BOE)	33.07	27.14	21.72	21.64	23.29
Costs per BOE:					
Lease operations	$ 5.22	$ 4.67	$ 4.15	$ 4.00	$ 3.99
Production, ad valorem, and severance taxes	3.36	2.71	2.12	2.20	3.24
Depletion, depreciation, and amortization	5.38	4.13	4.67	5.05	4.72

General and administrative (excluding non-cash stock based compensation)	1.22	1.07	0.83	0.80	0.93

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	Year Ended December 31,				
	2004	2003	2002	2001	2000
Proved Reserves:					
Oil (Bbls)	134,048	117,732	111,674	91,369	78,910
Natural gas (Mcf)	234,030	138,950	99,818	75,687	72,970
Combined (BOE)	173,053	140,890	128,310	103,983	91,072

	As of December 31,				
	2004	2003	2002	2001	2000
Consolidated Balance Sheet Data:					
Working capital	$ (15,566)	$ (52)	$ 12,489	$ 1,107	$ (15,275)
Total assets	1,123,400	672,138	549,896	402,000	343,756
Total debt	379,000	179,000	166,000	79,107	162,045
Stockholders equity	473,575	358,975	296,266	269,302	147,811

(1) For the years ended December 31, 2004, 2003, 2002, 2001, and 2000 we reduced revenue for the payments of the net profits interests by $12.6 million, $5.8 million, $2.0 million, $2.8 million, and $11.5 million, respectively.

(2) Net income for the year ended December 31, 2003 includes a $0.9 million cumulative effect of accounting change, which affects its comparability with other periods presented. See Pro Forma amounts presented in Note 5. Asset Retirement Obligations to the accompanying consolidated financial statements.

(3) Net income for the year ended December 31, 2001 includes $9.6 million of non-cash compensation expense, $4.3 million of bad debt expense, $1.6 million of impairment of oil and natural gas properties, and a $(0.9) million cumulative effect of accounting change, which affects its comparability with other periods presented.

(4) Net income for the year ended December 31, 2000 includes $26.0 million of non-cash compensation expense, which affects its comparability with other periods presented.

Item 7. ***Management s Discussion and Analysis of Financial Condition and Results of Operations***

The following discussion and analysis of our consolidated financial position and results of operations should be read in conjunction with our financial statements and notes and the supplemental oil and natural gas disclosures included elsewhere in this Report. 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, should and similar exp 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 the federal securities laws. Readers are cautioned that such forward-looking statements should be read in conjunction with our disclosures under the headings: Special Note Regarding Forward-Looking Statements beginning on page 41 and Factors That May Affect Future Results and Financial Condition beginning on page 42.

Overview

We engage in the acquisition, development, exploitation, exploration, and production of onshore North American oil and natural gas reserves. Our business strategies include maintaining an active low-risk development drilling program, maximizing existing reserves and production through high-pressure air injection projects, expanding our reserves, production and drilling inventory through a disciplined acquisition program, 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. Commodity prices strengthened considerably in 2004. The average oil price for the NYMEX futures market was $41.26 per barrel for 2004 as compared to $31.04 per barrel for 2003. The average natural gas price for the NYMEX futures market was $6.11 per MMBTU for 2004 as compared to $5.50 per MMBTU for 2003. Commodity prices are influenced by many factors that are outside of our control. We cannot predict future commodity prices. For this reason, we attempt to mitigate the effect of commodity price risk by hedging a portion of our future production.

In 2004, we saw the industry and commodity markets begin to reflect a higher long-term outlook for commodity prices. As a result during the year, the industry continued to bid up the price of reserves to historically high levels. However, we were fortunate to be able to expand our core areas with the purchase of Cortez Oil & Gas, Inc. and natural gas properties in the Overton Field. As the year progressed and the cost of acquisitions continued to rise, we began to identify exploration projects within our core areas that complemented our current asset portfolio. We believe the rate of return on our exploration projects will meet or exceed the rate of return available in the current acquisition market. We will, however, continue to evaluate acquisition opportunities as they arise and to the extent we believe we can expect to realize a good rate of return to our shareholders.

We continue to believe that a portfolio of long-lived quality assets will position the Company for future success, and that reserve replacement is a key statistical measure of our success in growing our asset base. During 2004, we replaced 456% of our 2004 production. Our development program replaced 210% of production and acquisitions replaced 246% of production. See Business and Properties General Oil and Natural Gas Production and Reserves on page 3 for the calculation of our reserve replacement ratios.

Also in 2004, we continued to see positive results from our Phase I high-pressure air injection project at the Pennel unit. Pennel is the largest unit of the CCA units. The Phase II implementation is anticipated to be complete by the end of 2005 and initial air injection is scheduled to begin in the second quarter of 2005. In the Little Beaver unit at the southern end of the CCA, we have completed the implementation of Phase I and II HPAI projects. Our independent reserve engineers, Miller and Lents, Ltd. estimated that we added 9.1 million and 12.5 million barrels, respectively, of proved undeveloped oil reserves associated with our high pressure air injection program at the end of 2004 and 2003. For the long term, we believe that high-pressure air injection technology can be applied throughout the Cedar Creek Anticline.

2004 Highlights

Our financial and operating results for the year ended December 31, 2004 include the following:

Oil and natural gas reserves increased 23% to 173 MMBOE. During 2004, we added 41.2 MMBOE, replacing 456% of the 9.0 MMBOE produced in 2004. See Business and Properties General Oil and Natural Gas Production and Reserves on page 3 for the calculation of our reserve replacement ratio. Oil reserves accounted for 77% of total proved reserves, and 71% of proved reserves are developed. The estimated pretax present value of our reserves increased by 59% to over $1.6 billion (using a 10% discount rate and constant year end prices of $43.46 for oil and $6.19 for natural gas). The Standardized Measure at December 31, 2004 is $1.2 billion. Standardized Measure differs from PV-10 by $458.9 million, because Standardized Measure includes the effect of asset retirement obligations and future income taxes.

Production volumes for 2004 increased 11% to 9.0 MMBOE (24,665 BOE per day) compared with 2003 production of 8.1 MMBOE (22,218 BOE per day). Oil represented 74% and 81% of our total production in 2004 and 2003, respectively. The increase in production is due to our continued successful development and exploitation program as well as acquisitions.

Net income for 2004 increased to $82.1 million, or $2.58 per diluted share, on revenues of $298.5 million. This compares to 2003 net income of $63.6 million, or $2.10 per diluted share, on revenues of $220.1 million. For 2004, cash flow from operations increased 39% to $171.8 million

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from $123.8 million in cash flow from operations in 2003. The increase in net income and cash flow from operations in 2004 was primarily a result of higher production and higher commodity prices throughout the year.

We invested $187.6 million in development, exploitation, and exploration projects during 2004, including $39.6 million in our high-pressure air injection projects in the Little Beaver unit and the Pennel unit of the CCA. In 2004, we drilled 168 gross operated productive wells and 67 gross non-operated productive wells, for a total of 235 gross productive wells for the year. On a net basis, we drilled 156.4 operated productive wells and participated in 8.8 non-operated productive wells in 2004. Out of the 168 (156.4 net) operated productive wells, 12 (11.5 net) wells were service wells. We also drilled 5 (4.5 net) non-productive wells in 2004, of which 4 (3.9 net) were exploratory wells.

We acquired natural gas producing properties and undeveloped leases in the Overton Field located in Smith County, Texas, additional interests in Elm Grove Field, and all of the capital stock of Cortez Oil & Gas, Inc.

On April 2, 2004, we issued and sold $150.0 million of 6$^{1}/4$% Senior Subordinated Notes due April 15, 2014. We received approximately $146.4 million after paying all costs associated with the offering. The net proceeds were used to fund the acquisition of Cortez and repay amounts outstanding under our revolving credit facility.

On June 10, 2004, we issued and sold 2,000,000 shares of our common stock to the public at a price of $26.95 per share. The net proceeds of the offering, after underwriting discounts and commissions and other expenses, were $52.9 million. We used the net proceeds of this offering to repay indebtedness under our revolving credit facility and for general corporate purposes.

On June 30, 2004, we filed a new universal shelf registration statement on Form S-3 with the SEC. The registration statement, which was declared effective by the SEC on July 9, 2004, allows us to issue an aggregate of $500 million of common stock, preferred stock, senior debt and subordinated debt.

On August 19, 2004, we improved our financial flexibility and liquidity by amending and restating our credit facility and increasing our borrowing base from $270 million to $400 million. At December 31, 2004, we had $79 million outstanding under the revolving credit facility, $30 million in outstanding letters of credit, and $291 million available.

Results of Operations

Comparison of 2004 to 2003

Set forth below is our comparison of our results of operations for the year ended December 31, 2004 with our results of operations for the year ended December 31, 2003.

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Revenues and Production. The following table illustrates the primary components of oil and natural gas revenue for the years ended December 31, 2004 and 2003, as well as each year s respective oil and natural gas volumes (dollars in thousands except per unit amounts):

	Year Ended December 31,					
	2004		2003		*Difference*	
	Revenue	$/Unit	Revenue	$/Unit	*Revenue*	*$/Unit*
Revenues:						
Oil wellhead	$ 255,394	$ 38.24	$ 190,203	$ 28.82	*$ 65,191*	*$ 9.42*
Oil hedges	(34,745)	(5.20)	(13,852)	(2.10)	*(20,893)*	*(3.10)*
Total Oil Revenues	$ 220,649	$ 33.04	$ 176,351	$ 26.72	*$ 44,298*	*$ 6.32*
Natural gas wellhead	$ 81,112	$ 5.76	$ 45,218	$ 5.00	*$ 35,894*	*$ 0.76*
Natural gas hedges	(3,228)	(0.23)	(1,473)	(0.17)	*(1,755)*	*(0.06)*
Total Natural Gas Revenues	$ 77,884	$ 5.53	$ 43,745	$ 4.83	*$ 34,139*	*$ 0.70*
Combined wellhead	$ 336,506	$ 37.28	$ 235,421	$ 29.03	*$ 101,085*	*$ 8.25*
Combined hedges	(37,973)	(4.21)	(15,325)	(1.89)	*(22,648)*	*(2.32)*
Total Combined Revenues	$ 298,533	$ 33.07	$ 220,096	$ 27.14	*$ 78,437*	*$ 5.93*

	Production	Average NYMEX $/Unit	Production	Average NYMEX $/Unit	*Production*	Average NYMEX $/Unit
Other data:						
Oil (MBbls)	6,679	$ 41.26	6,601	$ 31.04	*78*	*$ 10.22*
Natural Gas (MMcf)	14,089	6.11	9,051	5.50	*5,038*	*0.61*
Combined (MBOE)	9,027		8,110		*917*	

Oil revenues increased $44.3 million to $220.6 million in 2004 over 2003 as production increased 78 MBbls and our average realized price increased $6.32 per Bbl. Oil revenues were reduced by $34.7 million in 2004 due to our hedging program. The $5.20 per Bbl reduction to our wellhead oil price due to hedging represented a $3.10 per Bbl greater reduction than in 2003. The increase in oil production resulted from success through our 2004 drilling program, uplift from our HPAI program, and acquisitions. In addition, our oil wellhead revenue was reduced by $12.3 million and $5.6 million in 2004 and 2003, respectively, for the net profits interests payments related to our CCA properties.

Natural gas revenues increased in 2004 by $34.1 million to $77.9 million due to increased production of 5,038 MMcf and an increase in the net wellhead price received. The increase in net wellhead price received of $0.76 per Mcf resulted as the average NYMEX price increased $0.61 per Mcf over the same period. The increase in natural gas production resulted from success through our 2004 drilling program and acquisitions.

For the full year 2005, production is expected to increase 8% to 12% from 2004 levels primarily due to our 2005 capital budget of $223.0 million and the full year effect of our 2004 acquisitions.

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 on $30.00 per Bbl and $5.00 per Mcf NYMEX prices. We do not assume any escalation of commodity prices when preparing our capital budget. If NYMEX prices trend downward below our base deck, we may reevaluate our capital projects. At these assumed prices, we have forecasted net hedge contract payments of approximately $1.8 million for oil and $0.3 million for natural gas during 2005. However, these amounts will change directly with any change in the market price of oil and natural gas and with any change in our outstanding hedge positions. Additionally, we have anticipated net profits interests payments in 2005 of $6.2 million for oil and $0.1 million for natural gas. These payments are highly dependent on the level of drilling in the CCA and on commodity prices, and thus, any change in the level of drilling or fluctuation in commodity prices will have a direct impact on the amount of payments we are required to make. If commodity prices are significantly lower than our forecasted prices of $30.00 for oil and $5.00 for natural gas, it could have a material effect on our projected 2005 results. 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.

In addition to the possibility of a general market decline in oil and natural gas prices, a widening of the difference between the price we are paid and NYMEX prices, which we refer to as the differential, could have a material negative impact on our revenues. Due to a combination of higher prices and increased competition with foreign grades from both Canada and the Middle East, our differential to NYMEX oil widened in the second half of 2004. Early 2005 differentials to NYMEX oil also indicate a further widening. We expect our oil differential in 2005 to remain wider than 2004.

Expenses. The following table summarizes our expenses for the years ended December 31, 2004 and 2003:

	Year Ended December 31,		
	2004	**2003**	***Difference***
Expenses (in thousands):			
Lease operations	$ 47,142	$ 37,846	*$ 9,296*
Production, ad valorem, and severance taxes	30,313	22,013	*8,300*
Depletion, depreciation, and amortization	48,522	33,530	*14,992*
Exploration	3,907		*3,907*
General and administrative (excluding non-cash stock based compensation)	10,982	8,680	*2,302*
Non-cash stock based compensation	1,770	614	*1,156*
Derivative fair value (gain) loss	5,011	(885)	*5,896*
Other operating	5,028	3,481	*1,547*
Interest	23,459	16,151	*7,308*
Current and deferred income tax provision	40,492	36,102	*4,390*
Expenses (per BOE):			
Lease operations	$ 5.22	$ 4.67	*$ 0.55*
Production, ad valorem, and severance taxes	3.36	2.71	*0.65*
Depletion, depreciation, and amortization	5.38	4.13	*1.25*
Exploration	0.43		*0.43*
General and administrative (excluding non-cash stock based compensation)	1.22	1.07	*0.15*
Non-cash stock based compensation	0.20	0.08	*0.12*
Derivative fair value (gain) loss	0.56	(0.11)	*0.67*
Other operating	0.56	0.43	*0.13*
Interest	2.60	1.99	*0.61*
Current and deferred income tax provision	4.49	4.45	*0.04*

Lease operations expense. Lease operations expense increased by $9.3 million in 2004 as compared to 2003. The increase in total lease operations expense resulted from an increase in production volumes as a result of our 2004 drilling program, the Elm Grove, Cortez and Overton acquisitions and our HPAI program, as well as an increase in the per BOE rate. The increase in our average per BOE rate was attributable to acquired properties with higher per BOE expenses and an increase in prices paid for outside services.

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For 2005, we anticipate an increase in total lease operations expense on both an aggregate and a per BOE basis. We anticipate the overall increase due to a full year of production at our Cortez and Overton properties, as well as further implementation of the high-pressure air injection program. Currently, we are capitalizing the HPAI costs on the Little Beaver HPAI project, which will continue until the reservoir becomes fully pressurized. We expect the reservoir to become fully pressurized in 2005 and will begin expensing the costs of injecting air at that time. We have projected lease operations expense of $5.90 per BOE for 2005 as compared to $5.22 for 2004.

Production, ad valorem, and severance taxes. Production, ad valorem and severance taxes increased by $8.3 million in 2004 as compared to 2003. The increase in production, ad valorem, and severance taxes is a direct result of the increase in wellhead revenue. See Revenues and Production above. As a percentage of oil and natural gas revenues (excluding the effects of hedges), production, ad valorem, and severance taxes decreased slightly from 9.4% to 9.0% from 2003 to 2004.

For 2005, total production, ad valorem, and severance taxes will depend in a large part on prevailing oil and natural gas prices. However, the production, ad valorem, and severance tax rate should remain relatively flat at 9.0% of wellhead revenues before hedging.

Depletion, depreciation, and amortization (DD&A) expense. DD&A expense increased by $15.0 million in 2004 as compared to 2003. The increase was primarily due to an increase in production as well as a increase in the per BOE rate. This rate increase was due to the acquisition of the Overton and Cortez properties, which had higher acquisition costs than our historical average, as well as higher drilling costs per BOE of reserves than our historical DD&A rate in certain areas.

We anticipate the total DD&A expense in 2005 will increase due to increased production and our planned 2005 capital expenditures of $223.0 million. We expect the invested capital to add barrels through the drill bit in 2005 at a cost higher than our historical DD&A rate. Assuming capital expenditures do not differ significantly from our budgeted amount, we expect our DD&A rate for 2005 to be approximately $7.00 per BOE. This rate could vary significantly based on actual capital expenditures, production rates, net profits interests, and any acquisitions that close in 2005. Additionally, changes in the market price for oil and natural gas could affect the level of our reserves. As the level of reserves change, the DD&A rate is inversely affected.

Exploration expense. Exploration costs increased in 2004 as we began a drilling exploration program in 2004. As previously discussed, we drilled a record number of wells in 2004, several of which were exploratory wells. We drilled 4 (3.88 net) non-productive exploratory wells at a cost of $2.1 million. This compares to 2003 when zero non-productive exploratory wells were drilled. Three of the exploratory dry holes were drilled in our Montana shallow gas area and one was drilled in the Barnett Shale in our Mid-Continent area. In addition to the increase in dry hole expense, additional exploration-related expenses were incurred in 2004 related to our exploration projects. We incurred abandonment and impairment of undeveloped leases costs of $0.7 million, delay rental expense of $0.2 million, seismic costs of $0.6 million, and other geological and geophysical expenses of $0.3 million.

For 2005, we expect exploration expense to be approximately $6.2 million as we continue our current exploration projects in the Mid-Continent and Montana shallow gas area. This amount could vary considerably, however, based on the success of these projects.

General and administrative (G&A) expense. G&A expense increased by $2.3 million in 2004 over 2003. The increase in G&A expense was a result of increased staffing levels used to manage our growing asset base and outside consulting services used in the evaluation of potential acquisitions and costs associated with compliance with the Sarbanes-Oxley Act of 2002.

We have forecast approximately $14.0 million for general and administrative expenses in 2005 as compared to the $11.0 million incurred in 2004. The increase from 2004 is expected to result from increased staffing to manage our larger asset base, additional expenses related to compliance with the Sarbanes-Oxley Act of 2002, and higher directors and officers insurance costs. Additionally, we have

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experienced increased competition for human resources from other companies within the industry that has increased the cost to hire and retain experienced industry personnel.

Non-cash stock based compensation expense. Non-cash stock based compensation expense increased from $0.6 million in 2003 to $1.8 million in 2004. This expense represents the amortization of deferred compensation recorded in equity related to restricted stock granted under the 2000 Incentive Stock Plan. This amount is being amortized to expense over the vesting period of the restricted stock.

During the years ended December 31, 2004, 2003, and 2002, we issued 68,071, 45,461, and 77,901 shares, respectively, of restricted stock to employees which depend only on continued employment for vesting. The following table illustrates by year of grant the vesting of shares which remain outstanding at December 31, 2004:

	Year of Vesting					
Year of Grant	**2005**	**2006**	**2007**	**2008**	**2009**	**Total**
2002	23,775	23,775	23,774			71,324
2003		13,772	13,772	13,772		41,316
2004	19,423	19,423	22,690	3,268	3,267	68,071
Total	43,198	56,970	60,236	17,040	3,267	180,711

During the years ended December 31, 2004, 2003, and 2002, we issued 57,693, zero, and 51,427 shares of restricted stock to employees that not only depend on the passage of time and continued employment, but also on certain performance measures for their vesting. The following table illustrates by year of grant the vesting of shares which remain outstanding at December 31, 2004:

	Year of Vesting					
Year of Grant	**2005**	**2006**	**2007**	**2008**	**2009**	**Total**
2002	11,488	11,488	11,488			34,464
2003						
2004			19,231	19,231	19,231	57,693
Total	11,488	11,488	30,719	19,231	19,231	92,157

Deferred compensation of $3.4 million was reclassified within equity from additional paid in capital during the year ended December 31, 2004 in conjunction with the 2004 grants, and will be expensed over the related periods from the grant dates to the vesting dates.

Subsequent to December 31, 2004, we issued 164,703 shares of restricted stock to our employees as part of our annual incentive program. We have projected 2005 non-cash stock based compensation expense related to our restricted stock to be $1.4 million. This amount is dependent somewhat on fluctuations in our stock price because, as noted above, certain awards are accounted for as variable awards as they are based on achievement of certain performance measures.

Derivative fair value (gain) loss. The derivative fair value loss of $5.0 million in 2004 represents the ineffective portion of the mark-to-market loss on our derivative hedging instruments, settlements received on our fixed to floating interest rate swap, (gains) losses related to commodity derivatives not designated as hedges, and changes in the mark-to-market value of our fixed to floating interest rate swap.

In conjunction with the issuance of $8^{3}/8$% notes in June 2002, we entered into an interest rate swap, which swaps fixed rates to floating, with the intent of lowering our effective interest payments. As this transaction does not qualify for hedge accounting, changes in its fair market value, as well as settlements, are not recorded in interest expense, but in Derivative fair value (gain) loss on the Consolidated Statements of Operations. During 2004, a gain of $0.3 million related to this interest rate swap was recorded in Derivative fair value (gain) loss. See Note 12. Financial Instruments to the accompanying consolidated financial statements.

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The components of the derivative fair value (gain) loss reported for the year ended December 31, 2004 and 2003 are as follows (in thousands):

		Year Ended December 31,		
		2004	2003	*Increase/ (Decrease)*
Designated cash flow hedges:				
Ineffectiveness	Commodity contracts	$ 5,018	$ 818	*$ 4,200*
Undesignated derivative contracts:				
Mark-to-market (gain) loss	Interest rate swap	272	(2,098)	*2,370*
Mark-to-market (gain) loss	Commodity contracts	(279)	395	*(674)*
Derivative fair value (gain) loss		$ 5,011	$ (885)	*$ 5,896*

Ineffectiveness loss related to our contracts increased $4.2 million due primarily to an increase in oil differentials on our production in the CCA.

Other operating expense. Other operating expense increased $1.5 million in 2004 as compared to 2003. The increase in other operating expense is primarily attributable to $1.3 million increase in oil and natural gas transportation expense, $0.9 million increase in loss on sale of properties and $0.1 million increase in annual corporate taxes, offset by $0.8 million decrease in severance payments to former employees.

For 2005, we anticipate other operating expense to be approximately $6.4 million as compared to $5.0 million in 2004, which reflects the increased transportation costs associated with higher expected production volumes.

Interest expense. Interest expense for the year ended December 31, 2004 increased $7.3 million over 2003 due primarily to an increase in debt outstanding under our credit facility and the new 6^{1}/4% notes, offset slightly by a decrease in our weighted average interest rate from period to period. We incurred additional debt in 2004 to fund the Cortez and Overton acquisitions. The weighted average interest rate, net of hedges, for 2004 was 7.7% compared to 9.6% for 2003. This lower weighted average interest rate is the result of the issuance of $150 million aggregate principal amount of 6^{1}/4% senior subordinated notes in April 2004.

The following table illustrates the components of interest expense for 2004 and 2003 (in thousands):

	2004	2003	*Difference*
8^{3}/8% senior subordinated notes	$ 12,563	$ 12,563	*$*
6^{1}/4% senior subordinated notes	7,005		*7,005*
Revolving credit facility	1,565	453	*1,112*
Hedge loss amortization	546	1,910	*(1,364)*
Debt issuance cost amortization	969	714	*255*
Fees and other	811	511	*300*
Total	$ 23,459	$ 16,151	*$ 7,308*

Income tax expense. Income tax expense for 2004 increased $4.4 million over 2003. This increase is due primarily to the $23.8 million increase in income before income taxes from 2003 to 2004 offset by a decrease in our effective tax rate from 36.5% in 2003 to 33.0% in 2004. The decrease in effective income tax rate resulted from an incremental increase of $4.0 million for Section 43 credits ($6.1 million in Section 43 credits in 2004 as compared to $2.1 million in 2003) and the effect of the change in our state effective tax rate from 3.0% to 2.4% in 2004 due to changes in the asset mix and apportionment factors.

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Comparison of 2003 to 2002

Set forth below is our comparison of our results of operations for the year ended December 31, 2003 with our results of operations for the year ended December 31, 2002.

Revenues and Production. The following table illustrates the primary components of oil and natural gas revenue for the years ended December 31, 2003 and 2002, as well as each year s respective oil and natural gas volumes (dollars in thousands except per unit amounts):

	Year Ended December 31,					
	2003		2002		*Difference*	
	Revenue	$/Unit	Revenue	$/Unit	*Revenue*	*$/Unit*
Revenues:						
Oil wellhead	$ 190,203	$ 28.82	$ 141,119	$ 23.38	*$ 49,084*	*$ 5.44*
Oil hedges	(13,852)	(2.10)	(6,265)	(1.04)	*(7,587)*	*(1.06)*
Total Oil Revenues	$ 176,351	$ 26.72	$ 134,854	$ 22.34	*$ 41,497*	*$ 4.38*
Natural gas wellhead	$ 45,218	$ 5.00	$ 24,803	$ 3.03	*$ 20,415*	*$ 1.97*
Natural gas hedges	(1,473)	(0.17)	1,035	0.13	*(2,508)*	*(0.30)*
Total Natural Gas Revenues	$ 43,745	$ 4.83	$ 25,838	$ 3.16	*$ 17,907*	*$ 1.67*
Combined wellhead	$ 235,421	$ 29.03	$ 165,922	$ 22.42	*$ 69,499*	*$ 6.61*
Combined hedges	(15,325)	(1.89)	(5,230)	(0.70)	*(10,095)*	*(1.19)*
Total Combined Revenues	$ 220,096	$ 27.14	$ 160,692	$ 21.72	*$ 59,404*	*$ 5.42*

	Production	Average NYMEX $/Unit	Production	Average NYMEX $/Unit	*Production*	Average NYMEX $/Unit
Other data:						
Oil (MBbls)	6,601	$ 31.04	6,037	$ 26.08	*564*	*$ 4.96*
Natural Gas (MMcf)	9,051	5.50	8,175	3.36	*876*	*2.14*
Combined (MBOE)	8,110		7,399		*711*	

Oil revenues increased $41.5 million in 2003 over 2002 as production increased 564 MBbls and our average realized price increased $4.38 per Bbl. The increase in production resulted from our successful development drilling program and uplift from the HPAI program. Oil revenues were reduced by $13.9 million in 2003 due to our hedging program. The hedging per Bbl reduction to our wellhead oil price of $2.10 represented a $1.06 per Bbl greater reduction than in 2002. The increase in oil production resulted from success through our drilling program, uplift from our HPAI program, and acquisitions In addition, our oil wellhead revenue was reduced by $5.6 million and $2.0 million in 2003 and 2002, respectively, for the net profits interests payments made to others related to our CCA properties.

Natural gas revenues increased in 2003 by $17.9 million due to a 65% increase in the net wellhead price received along with increased production of 876 MMcf. The increase in net wellhead price received of $1.97 per Mcf resulted as the average NYMEX price increased $2.14 per Mcf over the same period. The natural gas production increase resulted from the Elm Grove acquisition during 2003. Averaging 7,984 Mcfe per day from July 31, 2003 (the date of acquisition) to December 31, 2003, the Elm Grove properties added 3,345 Mcfe per day to our average daily production for 2003.

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Expenses. The following table summarizes our expenses for the years ended December 31, 2003 and 2002:

	Year Ended December 31,		
	2003	**2002**	***Difference***
Expenses (in thousands):			
Production			
Lease operations	$ 37,846	$ 30,678	*$ 7,168*
Production, ad valorem, and severance taxes	22,013	15,653	*6,360*
Depletion, depreciation, and amortization	33,530	34,550	*(1,020)*
General and administrative (excluding non-cash stock based compensation)	8,680	6,150	*2,530*
Non-cash stock based compensation	614		*614*
Derivative fair value (gain) loss	(885)	(900)	*15*
Other operating	3,481	2,045	*1,436*
Interest	16,151	12,306	*3,845*
Current and deferred income tax provision	36,102	22,616	*13,486*
Expenses (per BOE):			
Production			
Lease operations	$ 4.67	$ 4.15	*$ 0.52*
Production, ad valorem, and severance taxes	2.71	2.12	*0.59*
Depletion, depreciation, and amortization	4.13	4.67	*(0.54)*
General and administrative (excluding non-cash stock based compensation)	1.07	0.83	*0.24*
Non-cash stock based compensation	0.08		*0.08*
Derivative fair value (gain) loss	(0.11)	(0.12)	*0.01*
Other operating	0.43	0.28	*0.15*
Interest	1.99	1.66	*0.33*
Current and deferred income tax provision	4.45	3.06	*1.39*

Lease operations expense. Lease operations expense increased by $7.2 million in 2003 as compared to 2002. The increase in total lease operations expense resulted from the increase in volumes as a result of our 2003 drilling program, the Elm Grove acquisition and HPAI program. See Revenues and Production above. On a per BOE basis, lease operations expense increased primarily due to (1) full year results of our Paradox Basin properties, which had higher average per BOE lease operations expense of $9.04 for 2003 compared to our average of $4.67 per BOE, (2) the HPAI project on the CCA properties, and (3) lower production volumes from our Lodgepole properties, which have low operating costs.

Production, ad valorem, and severance taxes. Production, ad valorem and severance taxes increased by $6.4 million in 2003 as compared to 2002. The increase in production, ad valorem, and severance taxes for the year ended December 31, 2003 as compared to 2002 is a direct result of the increase in wellhead revenue. See Revenues and Production above. As a percentage of oil and natural gas revenues (excluding the effects of hedges), production, ad valorem, and severance taxes increased slightly from 9.3% to 9.4% from 2002 to 2003.

Depletion, depreciation, and amortization (DD&A) expense. DD&A expense decreased by $1.0 million in 2003 as compared to 2002. Despite an increase in production, DD&A expense decreased in 2003 due to the adoption of SFAS 143 on January 1, 2003, which resulted in a lower per BOE rate. As a result of the adoption of SFAS 143, we can no longer assume proceeds received for the salvage value of our equipment will offset plugging and abandonment costs, and thus are now required to deduct salvage

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value from the book value of equipment in calculating our depreciable base. This was the primary driver of the decrease in the average DD&A rate from 2002 to 2003.

General and administrative (G&A) expense. G&A expense increased by $2.5 million in 2003 as compared to 2002. The increase in G&A expense was a result of increased staffing levels used to manage our growing asset base and outside consulting services used in the evaluation of potential acquisitions.

Non-cash stock based compensation expense. Non-cash stock based compensation expense increased from zero in 2002 to $0.6 million in 2003. This expense represents the amortization of deferred compensation, recorded in equity related to restricted stock granted under the 2000 Incentive Stock Plan. This amount is being amortized to expense over the vesting period of the restricted stock.

During 2002 and 2003, we issued 129,328 and 45,461 shares, respectively, of restricted stock to employees. Of these, 77,901 shares issued in 2002 and 45,461 shares issued in 2003 vest in equal installments on the third, fourth, and fifth anniversary of the date of the grant and depend only on continued employment for future issuance. These represent a fixed award per APB 25 and compensation expense will be recorded over the related service period. Of the remaining 51,427 shares issued in 2002, 34,464 remain outstanding at December 31, 2003. These were issued to two members of senior management and also vest in equal installments on the third, fourth, and fifth anniversary of the date of the grant. However, these shares not only depend on the passage of time and continued employment, but on certain performance measures for their future issuance. These represent a variable award under APB 25 and, thus, the full amount of compensation expense to be recorded for these shares will not be known until their eventual issuance.

Derivative fair value gain/loss. The derivative fair value gain of $0.9 million in 2003 represents the ineffective portion of the mark-to-market loss on our derivative hedging instruments, settlements received on our fixed to floating interest rate swap, any commodity derivatives not designated as hedges, and changes in the mark-to-market value of our fixed to floating interest rate swap.

In conjunction with the issuance of $8^3/8$% notes in June 2002, we entered into an interest rate swap, which swaps fixed rates to floating, with the intent of lowering our effective interest payments. As this transaction does not qualify for hedge accounting, changes in its fair market value, as well as settlements, are not recorded in interest expense, but in Derivative fair value (gain) loss on the Consolidated Statements of Operations. During 2003, a gain of $1.5 million related to this interest rate swap was recorded in Derivative fair value (gain) loss. See Note 12. Financial Instruments to the accompanying consolidated financial statements.

Other operating expense. Other operating expense for the year ended December 31, 2003 increased by approximately $1.4 million as compared to 2002. This amount primarily consists of 2003 severance payment obligations to former employees. The remaining amount relates to the inclusion of accretion expense on our SFAS 143 future abandonment liability; and the abandonment in undeveloped leasehold costs.

Interest expense. Interest expense for the year ended December 31, 2003 increased $3.8 million over 2002 due primarily to an increase in our weighted average interest rate from period to period, as well as an increase in debt outstanding related to our credit facility. We incurred additional debt in 2003 to fund the North Louisiana acquisition. The weighted average interest rate, net of hedges, for 2003 was 9.6% compared to 8.2% for 2002. This higher weighted average interest rate is the result of the issuance of $150 million aggregate principal amount of $8^3/8$% senior subordinated notes in June 2002, which was the primary component of our total indebtedness during 2003, while the revolving credit facility with a lower floating rate was the primary component during the first half of 2002.

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The following table illustrates the components of interest expense for 2003 and 2002 (in thousands):

	2003	2002	*Difference*
8 3/8% senior subordinated notes	$ 12,563	$ 6,488	*$ 6,075*
Revolving credit facility	453	2,260	*(1,807)*
Hedge settlements		1,249	*(1,249)*
Hedge loss amortization	1,910	1,619	*291*
Debt issuance cost amortization	714	314	*400*
Fees and other	511	376	*135*
Total	$ 16,151	$ 12,306	*$ 3,845*

Income tax expense. Income tax expense for 2003 increased $13.5 million over 2002. This increase is due primarily to the $38.6 million increase in income before income taxes from 2002 to 2003. Our effective income tax rate, prior to adjusting for Section 43 credits, remained at a constant 38% for both 2002 and 2003. However, during 2003, we generated $2.1 million in Section 43 credits, as compared to $1.1 million of Section 43 credits generated in 2002. This increase resulted in an effective income tax rate of 36.5% in 2003, a decrease of 1% from our 2002 effective rate of 37.5%.

Description of Critical Accounting Estimates

Oil and Natural Gas Properties

Successful efforts method. We utilize the successful efforts method of accounting for our oil and gas properties. Under this method, all costs associated with productive and nonproductive development wells are capitalized. Exploration expenses, including geological and geophysical expenses and delay rentals, are charged to expense as incurred. Costs associated with exploratory wells are initially capitalized pending determination of whether the well is economically productive or nonproductive.

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

Significant tangible equipment added or replaced is capitalized. Expenditures to construct facilities or increase the productive capacity from existing reserves are capitalized. Internal costs directly associated with the development and exploitation of properties are capitalized as a cost of the property and are classified accordingly in our consolidated financial statements. Capitalized costs are amortized on a unit-of-production basis over the remaining life of proved developed reserves or proved reserves, as applicable. Natural gas volumes are converted to equivalent barrels of oil at the rate of six Mcf to one barrel. See Note 2. New Accounting Standards, to the accompanying consolidated financial statements for a discussion of Statement of Financial Accounting Standard No. 143, Accounting for Asset Retirement

Obligations (SFAS 143), which we adopted as of January 1, 2003.

Unproved Properties. We adhere to Statement of Financial Accounting Standards No. 19, Financial Accounting and Reporting by Oil and Gas Producing Companies, for recognizing any impairment of capitalized costs to unproved properties. The greatest portion of these costs generally relate to the acquisition of leasehold costs. The costs are capitalized and periodically evaluated as to recoverability, based on changes brought about by economic factors and potential shifts in business strategy employed by management. We consider a combination of time and geologic and engineering factors to evaluate the need for impairment of these costs. Unproved properties had a net book value of $29.7 million and $0.9 million as of December 31, 2004 and 2003, respectively. We recorded a charge for unproved acreage impairment in the amount of $0.7 million, $0.4 million, and zero in 2004, 2003, and 2002, respectively.

Oil and Natural Gas Reserves. Assumptions used by the independent reserve engineers in calculating reserves or regarding the future cash flows or fair value of our properties are subject to change in the future. Future prices received for production and future production costs may vary, perhaps significantly, from the prices and costs assumed for purposes of calculating reserve estimates. We may not be able to develop proved reserves within the periods estimated. Furthermore, prices and costs will not remain constant. Actual production may not equal the estimated amounts used in the preparation of reserve projections. As these estimates change, the amount of calculated reserves change. Any change in reserves directly impacts our estimate of future cash flows from the property, as well as the property s fair value.

Impairment. Impairments of proved oil and natural gas properties are directly affected by our reserve estimates. We are required to assess the need for an impairment of capitalized costs of oil and natural gas properties and other long-lived assets whenever events or circumstances indicate that the carrying value of those assets may not be recoverable. If impairment is indicated based on a comparison of the asset s carrying value to its undiscounted expected future net cash flows, then it is recognized to the extent that the carrying value exceeds fair value. Each part of this calculation is subject to a large degree of management judgment, including the determination of property s reserves, amount and timing of future cash flows, and fair value.

Depletion, Depreciation, and Amortization (DD&A). DD&A expense is directly affected by our reserve estimates. Any change in reserves directly impacts the amount of DD&A expense that we recognize in a given period. Assuming no other changes, such as an increase in depreciable base, as our reserves increase, the amount of DD&A expense in a given period decreases and vice versa. Changes in future commodity prices would likely result in increases or decreases in estimated recoverable reserves. Additionally, Miller & Lents, Ltd., our independent reserve engineers, estimate our reserves once a year at December 31.

Goodwill

Goodwill represents the excess of the purchase price over the estimated fair value of the net assets acquired in the purchase of Cortez Oil & Gas, Inc. in April 2004 (see Note 3, Acquisitions). We test goodwill for impairment quarterly by applying a fair-value based test. We would recognize an impairment charge for any amount by which the carrying amount of goodwill exceeds its fair value. We tested goodwill for impairment and used discounted cash flows to establish fair values for the Company as a whole. The test indicated no impairment for 2004.

Net Profits Interests

A major portion of our acreage position in the Cedar Creek Anticline is subject to net profits interests (NPI) ranging from 1% to 50%. The holders of these net profits interests are entitled to receive a fixed percentage of the cash flow remaining after specified costs have been deducted from net revenue. The net profits calculations are contractually defined, but in general, net profits are determined after considering operating expense, overhead expense, interest expense, and drilling costs. The amounts of reserves and production calculated to be attributable to these net profits interests are deducted from our reserves and production data, and our revenues are reported net of NPI payments. The reserves and production that are attributed to the NPIs are calculated by dividing estimated future NPI payments (in the case of reserves) or prior period actual NPI payments (in the case of production) by the commodity prices current at the determination date. Fluctuations in commodity prices and the levels of development activities in the CCA from period to period will impact the reserves and production attributed to the NPIs and will have an inverse effect on our reported reserves and production. Based largely on higher commodity prices, we expect to make higher net profit interest payments in 2005 and possibly beyond than we have in previous years, which directly impacts our revenues, production, reserves, and net income.

Revenue Recognition

Revenues are recognized for our share of jointly owned properties as oil and natural gas is produced and sold, net of royalties and net profits interest payments. Natural gas revenues are also reduced by any processing and other fees paid except for transportation costs paid to third parties which are recorded as expense. Natural gas revenue is recorded using the sales method of accounting whereby revenue is recognized as natural gas is sold rather than as it is produced. Royalties, net profits interests, and severance taxes are paid based upon the actual price received from the sales. To the extent actual quantities and values of oil and natural gas are unavailable for a given reporting period because of timing or information not received from third parties, we estimate and record the expected sales volumes and price for those properties. We also do not recognize revenue for the production in tanks or pipelines that has not been delivered to the purchaser yet. Our net oil inventories in pipelines were 43,010 Bbls and 46,622 Bbls at December 31, 2004 and 2003, respectively. Natural gas imbalances under-delivered to us at December 31, 2004 and December 31, 2003, were 540,000 MMBTU and 446,000 MMBTU, respectively.

Income Taxes

Section 43 Credits. Section 43 of the Internal Revenue Code (the Code) allows a 15 percent tax credit for certain enhanced oil recovery project costs incurred in the United States. We believe project costs incurred related to our HPAI tertiary recovery project on the CCA qualify under the provisions of the Code and, therefore, we have reduced income tax expense by 15 percent of project costs incurred to date. The tax basis for the properties (and related intangible drilling cost deductions and future depreciation deductions) is reduced by the amount of the enhanced oil recovery tax credit. In order to qualify for the credits a project must meet all of the following requirements:

1. The project involves the application of one or more qualified tertiary recovery methods that is reasonably expected to result in more than an insignificant increase in the amount of crude oil that ultimately will be recovered;

2. The project is located within the United States;

3. The first injection of liquids, gases, or other matter for the project occurs after December 31, 1990; and

4. The project is certified by a petroleum engineer.

According to the Code, the costs that will qualify for the credit when paid or incurred in connection with a qualifying enhanced oil recovery project include:

1. *Tangible Property.* Any amount paid for tangible property that is an integral part of a qualified enhanced oil recovery project, and with respect to which depreciation is allowable.

2. *Intangible Drilling and Development Costs.* Intangible drilling cost with respect to which the taxpayer may make an intangible drilling costs deduction election under Code Sec. 263(c).

3. *Qualified Tertiary Injectant Expenses.* Any qualified tertiary injectant expenses for which a deduction is allowable under any Code section.

If our federal income tax returns are reviewed by the Internal Revenue Service (the IRS), the IRS could disagree with our decision and disallow a portion of the credit. While we believe our HPAI project qualifies for the tax credit and that our accounting and tracking of the costs related to the project are

accurate, should the IRS disagree with our position, we would be required to record additional income tax expense to the extent income tax expense has previously been reduced related to the generation of Section 43 credits.

Effective Tax Rate. The Company s effective tax rate is subject to variability from period to period as a result of factors other than changes in federal and state tax rates and/or changes in tax laws which can affect tax paying companies. Currently, our effective tax rate varies primarily as the amount of Section 43 income tax credits generated varies from period to period. These credits are generated by paying or incurring certain costs in connection with a qualifying enhanced oil recovery project, such as our current high-pressure air injection projects underway in the CCA. Our effective tax rate is also affected by changes in the allocation of property, payroll, and revenues between states in which we own property as rates vary from state to state.

Stock-based Compensation

Employee stock options and restricted stock awards are accounted for under the provisions of Accounting Principles Board Opinion No. 25 (APB 25), Accounting for Stock Issued to Employees. Accordingly, no compensation is recorded for stock options that are granted to employees or non-employee directors with an exercise price equal to or above the common stock price on the grant date. If compensation expense for the stock based awards had been determined using the provisions of SFAS 123, our net income and net income per share would have been adjusted to the pro forma amounts indicated below (in thousands, except per share amounts):

	Year Ended December 31,		
	2004	**2003**	**2002**
As Reported:			
Non-cash stock based compensation (net of taxes)	$ 1,108	$ 381	$
Net income	82,147	63,641	37,685
Basic net income per share	2.62	2.11	1.25
Diluted net income per share	2.58	2.10	1.25
Pro Forma:			
Non-cash stock based compensation (net of taxes)	$ 2,289	$ 1,929	$ 1,277
Net income	80,966	62,093	36,408
Basic net income per share	2.58	2.06	1.21
Diluted net income per share	2.54	2.05	1.21

During the year ended December 31, 2004, 6,509 employee stock options and 9,236 shares of restricted stock that were issued and outstanding at December 31, 2003 were forfeited.

Hedging and Related Activities

We use various financial instruments for non-trading purposes to manage and reduce price volatility and other market risks associated with our crude oil and natural gas production. These arrangements are structured to reduce our exposure to commodity price decreases, but they can also limit the benefit we might otherwise receive from commodity price increases. Our risk management activity is generally accomplished through over-the-counter forward derivative contracts executed with large financial institutions. We also use derivative instruments in the form of interest rate swaps, which hedge our risk related to interest rate fluctuation.

We currently recognize all of our derivative and hedging instruments in our statements of financial position as either assets or liabilities and measure them at fair value. If a derivative does not qualify for hedge accounting, it must be adjusted to fair value through earnings. However, if a derivative does qualify for hedge accounting, depending on the nature of the hedge, changes in fair value can be offset against the

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change in fair value of the hedged item through earnings or recognized in other comprehensive income until such time as the hedged item is recognized in earnings.

To qualify for cash flow hedge accounting, the cash flows from the hedging instrument must be highly effective in offsetting changes in cash flows due to changes in the underlying items being hedged. In addition, all hedging relationships must be designated, documented, and reassessed periodically. Most of our derivative financial instruments qualify for hedge accounting. Cash flow hedges are marked-to-market through comprehensive income each quarter.

Currently, all of our derivative financial instruments that are designated as hedges are designated as cash flow hedges. These instruments hedge the exposure of variability in expected future cash flows that is attributable to a particular risk. The effective portion of the mark-to-market gain or loss on these derivative instruments is recorded in Other Comprehensive Income in Stockholders Equity and reclassified into earnings in the same period in which the hedged transaction affects earnings. Any ineffective portion of the gain or loss is recognized as Derivative fair value (gain) loss in the Consolidated Statements of Operations immediately. While management does not anticipate changing the designation of any of our current derivative contracts as hedges, factors beyond our control can preclude the use of hedge accounting. One example would be variability in the NYMEX price for oil or natural gas, upon which many of our commodity derivative contracts are based, that does not coincide with changes in the spot price for oil and natural gas that we are paid. Another example would be if the counterparty to a derivative contract was deemed no longer creditworthy and non-performance under the terms of the contract was likely. To the extent our derivative contracts are not designated as hedges, high earnings volatility can result, as any future changes in the market value of the contract would then be marked-to-market through earnings.

New Accounting Standards

In December 2004, the FASB issued Statement No. 123 (revised 2004), Share-Based Payment (SFAS 123(R)), which replaces SFAS 123, Accounting for Stock-Based Compensation, and supersedes APB 25. SFAS 123(R) requires the measurement of all share-based payments to employees, including grants of employee stock options, using a fair-value-based method and the recording of expense in our Consolidated Statements of Operations. The accounting provisions of SFAS 123(R) are effective for reporting periods beginning after June 15, 2005. We are required to adopt SFAS 123(R) in the third quarter of 2005. The pro forma disclosures previously permitted under SFAS 123 no longer will be an alternative to financial statement recognition. See Stock-based Compensation above for the pro forma net income and net income per share amounts, for fiscal 2002 through fiscal 2004, as if we had used a fair-value-based method similar to the methods required under SFAS 123(R) to measure compensation expense for employee stock incentive awards.

In December 2004, the FASB issued FASB Staff Position No. FAS 109-1 (FAS 109-1), Application of FASB Statement No. 109, Accounting for Income Taxes, to the Tax Deduction on Qualified Production Activities Provided by the American Jobs Creation Act of 2004. The American Jobs Creation Act introduces a new IRS code section, Section 199, which provides a deduction equal to 3% (increasing to 9% when fully phased-in in 2010) of taxable income from a qualified production activity. FAS 109-1 clarifies that this tax deduction should be accounted for as a special tax deduction in accordance with Statement 109, thereby reducing tax expense in the periods in which the deductions are deductible on the tax return. We do not expect the adoption of these new tax provisions to have a material impact on our consolidated financial position, results of operations, or cash flows.

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Capital Resources, Capital Commitments, and Liquidity

Capital Resources and Capital Commitments

Our primary capital resources are net cash provided by operating activities and proceeds from financing activities. Our primary needs for cash are as follows:

- Development, exploitation, and exploration of our existing oil and natural gas properties
- High-pressure air injection programs on our CCA properties
- Acquisitions of oil and natural gas properties
- Leasehold and acreage costs
- Other general property and equipment
- Funding of necessary working capital
- Payment of contractual obligations

For 2005, our Board of Directors has approved the following $223.0 million capital budget, excluding potential proved property acquisitions (in thousands):

		2005
Budgeted Capital Expenditures:		
Development, exploitation, and exploration	$	191,500
HPAI		26,000
Leasehold and acreage acquisition		4,000
Other PP&E		1,500
Total	$	223,000

We analyze our inventory of capital projects based on $30.00 per Bbl and $5.00 per Mcf NYMEX prices. We do not assume any escalation of commodity prices when preparing our capital budget. If NYMEX prices trend downward below our base deck, we may reevaluate capital projects and may adjust the capital budgeted for development, exploitation, and exploration investments accordingly.

Development, Exploitation, and Exploration. Our capital expenditures for development, exploitation, and exploration during the years ended December 31, 2004, 2003, and 2002 were as follows (in thousands):

	Year Ended December 31,					
		2004		2003		2002
Development, Exploitation, and Exploration Expenditures:						
Development and exploitation	$	117,464	$	86,078	$	73,671
HPAI		39,628		12,899		6,642
Exploration		30,546				
Total	$	187,638	$	98,977	$	80,313

For 2005, we expect to invest $191.5 million in development, exploitation, and exploration projects.

High-Pressure Air Injection. In 2003, we began implementing our second HPAI program in the Little Beaver unit of the CCA and began injecting air in the reservoir in December 2003. At Little Beaver, we completed the implementation of Phase I and Phase II during 2004. The reservoir is pressuring up in line with forecasts and we expect to see initial production uplift mid-year 2005. In 2002 we began Phase I of Little Beaver unit of CCA spending $6.6 million in development capital.

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For 2005, we have budgeted $26.0 million for high-pressure air injection capital, primarily related to our Pennel program.

Acquisitions, Leasehold and Acreage Costs. Our capital expenditures for oil and natural gas proved property acquisitions during the years ended December 31, 2004, 2003, and 2002 were as follows (in thousands):

	Year Ended December 31,		
	2004	**2003**	**2002**
Acquisitions, Leasehold and Acreage Costs:			
Acquisitions	$ 204,907	$ 54,484	$ 78,158
Leasehold and acreage costs	33,926	117	391
Total	$ 238,833	$ 54,601	$ 78,549

In 2004, we completed the Cortez and Overton acquisitions. In 2003, we completed an acquisition of interests in natural gas properties in the Elm Grove field in North Louisiana. In 2002, we completed the Central Permian acquisition from Conoco for approximately $50.1 million, and a second, follow-on acquisition of additional working interest for $8.3 million. Also in 2002, we acquired an interest in oil and natural gas properties in southeast Utah s Paradox Basin.

We do not budget for acquisitions but we will continue to evaluate acquisition opportunities as they arise in 2005 with the same disciplined commitment to acquire assets that fit our portfolio and continue to create value. We will continue to pursue acquisitions of properties with similar upside potential to our current producing properties portfolio.

Because of the current high oil price environment, acquiring good quality oil and natural gas properties that are predictable, exploitable, and profitable is increasingly difficult. Success in the acquisition market depends largely on the level of competition in the marketplace and the availability of properties for sale.

Our current $223.0 million capital budget for 2005 does not include any funds for the development and exploitation of oil and natural gas properties that we may acquire during 2005. Our practice is to review our capital budget following a significant acquisition.

Our capital expenditures for leasehold and acreage costs during the years ended December 31, 2004, 2003, and 2002 totaled $33.9 million and $0.1 million, $0.4 million, respectively. Leasehold costs incurred in 2004 are higher than in the past primarily because of the Cortez, Overton, and Montana shallow gas acreage acquisitions during the year. Of the $33.9 million of capital expenditures for unproved property in 2004, $3.0 million and $18.4 million relate to the Cortez and Overton acquisitions respectively, $7.9 million relates to leases acquired in our Montana shallow gas area, and the remaining $4.6 million relates to unproved acreage spread over our other core areas.

For 2005, we expect to invest $4.0 million for the acquisition of leasehold and acreage costs primarily in our core areas.

Other General Property and Equipment. Our capital expenditures for other general property and equipment during the years ended December 31, 2004, 2003, and 2002 totaled $7.6 million, $1.5 million, and $0.7 million, respectively. Capital expenditures for other general property and equipment include aircraft, corporate leasehold improvements, computers, and various equipment.

For 2005, we expect to invest $1.5 million in other general property and equipment.

Working Capital. At December 31, 2004, our working capital was $(15.6) million while at December 31, 2003 working capital was $(0.1) million, a decrease of $15.5 million. At December 31, 2002, working capital was $12.5 million. The decrease from 2003 to 2004 was driven largely by an increase in our current derivative liability reflecting the current high commodity price environment. Higher working capital in 2002 was due to cash reserves held to maintain margin calls.

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For 2005, we expect working capital to approximate $(29.5) million. Negative working capital is expected mainly due to fair values of our derivative contracts which obligations will be offset by cash flows from hedged production. We anticipate cash reserves to be close to zero as we use any excess cash to fund capital obligations and any additional excess cash would be used to pay down our existing credit facility. We do not plan to pay cash dividends in the foreseeable future. The overall 2005 commodity prices for oil and natural gas will be the largest variable driving the different components of working capital. Our operating cash flow is determined in a large part by commodity prices. Assuming moderate to high commodity prices, our operating cash flow should remain positive for the foreseeable future. We have budgeted capital expenditures of approximately $223 million for 2005. The level of these and other future expenditures is largely discretionary, and the amount of funds devoted to any particular activity may increase or decrease significantly, depending on available opportunities and market conditions. We plan to finance our ongoing expenditures using internally generated cash flow, cash on hand, and our existing credit agreement.

Contractual Obligations. The following table illustrates our contractual obligations and commercial commitments outstanding at December 31, 2004 (in thousands):

	Payments Due by Period				
Contractual Obligations and Commercial Commitments	**Total**	**2005**	**2006-2007**	**2008-2009**	**Thereafter**
$8^3/8$% Notes(1)	$ 244,219	$ 12,563	$ 25,125	$ 25,125	$ 181,406
$6^1/4$% Notes(1)	239,063	9,375	18,750	18,750	192,188
Revolving Credit Facility(1)	87,814	2,768	5,535	79,511	
Derivative Obligations(2)	53,501	22,885	19,203	11,413	
Development Commitments(3)	16,321	15,421	600	300	
Operating Leases(4)	12,561	1,329	2,932	2,902	5,398
Totals	$ 653,479	$ 64,341	$ 72,145	$ 138,001	$ 378,992

(1) Amounts included in the table above include both principal and projected interest payments. See information presented in Note 7. Indebtedness to the accompanying consolidated financial statements for additional information regarding our long-term debt.

(2) Derivative obligations represent liabilities for derivatives that were valued as of December 31, 2004. The ultimate settlement amounts of the remaining portions of our derivative obligations are unknown because they are subject to continuing market risk. See Item 7A. Quantitative and Qualitative Disclosures about Market Risk and Note 12. Financial Instruments to the accompanying consolidated financial statements for additional information regarding our derivative obligations.

(3) Development commitments represent authorized purchases, $14.5 million of which represents work in process and is accrued at December 31, 2004. At December 31, 2004, we had $125.1 million of authorized purchases not placed to vendors (authorized AFEs) which were not accrued at year-end, but are budgeted for and expected to be made during 2005 unless circumstances change. Development commitments in the above table also include minimum transmission payments for electricity and compression services.

(4) Operating leases represent office space and equipment obligations that have remaining non-cancelable lease terms in excess of one year. See Note 4. Commitments and Contingencies to the accompanying consolidated financial statements for additional information regarding our operating leases.

Investing Activities. Cash used by investing activities increased by $279.7 million from 2003 to 2004. This was due to increases in the two primary components: acquisitions, which increased by $185.5 million; and development of oil and natural gas properties, which increased $87.5 million. During 2004, we purchased Cortez Oil & Gas, Inc. at a cost of $123.8 million, net of cash acquired; bought properties in the Overton Field at a cost of $83.1 million; and acquired other proved and unproved oil and natural gas properties totaling $33.2 million. In 2003 we acquired oil and natural gas properties totaling $54.6 million.

The increase in cash used in the development of oil and natural gas properties of $87.5 million in 2004 over 2003 was the result of drilling 102 more gross wells (66.0 net) and the expansion of the HPAI projects.

Cash used by investing activities decreased by $5.6 million from 2002 to 2003. This was due to offsetting changes in its two primary components: acquisition of oil and natural gas properties, which decreased by $23.9 million; and development of oil and natural gas properties, which increased $18.7 million. Cash used for the acquisition of oil and natural gas properties varies year to year based on our success in acquiring oil and natural gas properties. During 2002, we completed two major property acquisitions, the properties in the Paradox Basin of Utah and the properties in the Permian Basin of West Texas at a combined cost of $78.6 million, while in 2003 we completed one major property acquisition, the Elm Grove properties in the North Louisiana Salt Basin at a cost of $54.6 million. The increase in cash used in the development of oil and natural gas properties of $18.7 million was the result of drilling 29 more gross wells (8.3 net) in 2003 than in 2002 and the expansion of the HPAI project into the Little Beaver unit of the CCA.

Operating Activities. For 2004, cash provided by operating activities increased by $48.0 million, primarily because of increased revenues due to increased production volumes and higher commodity prices compared to 2003. This increase resulted primarily from the $18.5 million increase in net income coupled with an increase of DD&A expense of $15.0 million and non-cash derivative fair value loss of $12.7 million, offset by decrease in changes in operating assets and liabilities from 2003 to 2004 of $5.8 million.

Cash provided by operating activities increased by $32.3 million from 2002 to 2003. This increase resulted from the $26.0 million increase in net income coupled with an increase in deferred taxes of $11.8 million, offset by decrease in changes in operating assets and liabilities from 2002 to 2003 of $6.4 million. The increase in net income was primarily due to increased production volumes and higher commodity prices compared to 2002.

Financing Activities. On April 2, 2004, we sold $150 million of $6^{1}/4$% Senior Subordinated Notes due 2014 in a private placement. We received net proceeds of $146.4 million after deducting commissions and paying other costs associated with the offering. The $6^{1}/4$% notes were resold by the initial purchasers pursuant to 144A and Regulation S. The privately placed notes were subsequently exchanged for registered notes with substantially identical terms.

Additionally, in 2004 we improved our financial flexibility and liquidity by amending and restating our credit facility and increasing our borrowing base from $270 million to $400 million. At December 31, 2004, we had $79 million outstanding on the borrowing base, $30 million in outstanding letters of credit, and $291 million available.

On June 10, 2004, we issued and sold 2,000,000 shares of our common stock to the public at a price of $26.95 per share. The net proceeds of the offering, after underwriting discounts and commissions and other expenses, were approximately $52.9 million. We used the net proceeds of this offering to repay indebtedness under our revolving credit facility and for general corporate purposes.

On June 30, 2004, we filed a new universal shelf registration statement on Form S-3 with the SEC. The registration statement, which was declared effective by the SEC on July 9, 2004, allows us to issue an aggregate of $500 million of common stock, preferred stock, senior debt and subordinated debt.

During 2003 proceeds from financing activities were $17.3 million as compared to $80.7 million in 2002. In 2003, we were able to close the initial Elm Grove acquisition and subsequent interests for $54.6 million and fund our $99.0 million capital drilling program with only a modest $13.0 million increase in our revolving credit facility. During 2002, however, we increased our debt by $88.0 million to fund two property acquisitions, Central Permian and Paradox Basin, and fund $80.3 million in development expenditures.

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Liquidity

Our principal source of short-term liquidity is our revolving credit facility. We amended and restated our revolving credit facility on August 19, 2004. The amended and restated five-year senior secured credit facility is with a bank syndicate comprised of Bank of America, N.A. and other lenders. The amount we are able to borrow under the amended and restated credit facility is determined through semi-annual borrowing base determinations and may be increased or decreased. The initial borrowing base is $400 million and may be increased to up to $750 million. The initial borrowing base of $400 million reflects an increase of $130 million as compared to our $270 million borrowing base prior to August 19, 2004. The amended and restated credit facility matures on August 19, 2009. The amended and restated credit facility replaces our previous $300 million credit facility, which would have matured in June 2006.

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

Amounts outstanding under the amended and restated credit facility are subject to varying rates of interest based on (1) the amount outstanding under the amended and restated credit facility in relation to the borrowing base and (2) whether the loan is a Eurodollar loan or a base rate loan. The following table summarizes the calculation of the various interest rates for both Eurodollar and Base Rate loans:

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

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

(b) The Base Rate is calculated as the highest of (1) the annual rate of interest announced by Bank of America, N.A. as its prime rate and (2) the federal funds effective rate plus 0.5%.

The borrowing base will be redetermined each June 1 and December 1, commencing June 1, 2005. The bank syndicate has the ability to request one additional borrowing base redetermination per year, and we are permitted to request two additional borrowing base redeterminations per year. Generally, if amounts outstanding ever exceed the borrowing base, we must reduce the amounts outstanding to the redetermined borrowing base within six months, provided that if amounts outstanding exceed the borrowing base as a result of any sale of our assets or permitted subordinated debt, we must reduce the amounts outstanding immediately upon consummation of the sale.

Borrowings under the amended and restated credit facility may be repaid at anytime without penalty.

Our revolving credit facility and the indentures related to the $8^3/8$% and $6^1/4$% notes contain financial and other restrictive covenants that limit our ability to engage in activities that may be in our long-term best interests. The covenants under our revolving credit facility are similar but generally more restrictive than the covenants under the indentures. Our ability to borrow under our revolving credit facility is subject to financial covenants, including leverage, interest and fixed charge coverage ratios. Our revolving credit facility limits our ability to effect mergers, asset sales, and change of control events. These covenants also contain restrictions regarding our ability to incur additional indebtedness in the future. In some cases, our subsidiaries are subject to similar restrictions that may restrict their ability to make distributions to us. The indentures related to our $8^3/8$% and $6^1/4$% notes also contains limitations on our ability to effect mergers and change of control events, incur additional indebtedness, sell assets, declare and pay dividends or make other restricted payments, enter into transactions with affiliates and subject our assets to liens.

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Based on current commodity price conditions, we believe that our capital resources are adequate to meet the requirements of our business through 2005. Based on our anticipated capital programs, we expect to invest our internally generated cash flow to replace production and enhance our development programs. During 2005, we have planned total capital expenditures of approximately $223.0 million, although we may need additional capital to pursue acquisitions or other capital projects. Our current capital budget does not include any funds for development, exploitation, and exploration of oil and natural gas properties that we may acquire during 2005. Our practice is to review our capital budget following a significant transaction.

Substantially all of our capital expenditures are discretionary and will be undertaken only if funds are available and the projected rates of return are satisfactory. Future cash flows are subject to a number of variables including the level of oil and natural gas production and prices. Operations and other capital resources may not provide cash in sufficient amounts to maintain planned levels of capital expenditures. Additionally, we are required to maintain margin amounts and/or letters of credits with the counterparties to our outstanding hedges if the mark-to-market value of our hedges reaches a certain negative value. Although we did not have any margin deposits with our counterparties as of December 31, 2004, if commodity prices were to rise substantially, we would be required to post margin with one or more counterparties to secure future hedging settlements. As of February 28, 2005, we have $5.3 million posted related to our derivatives margin accounts.

Book capitalization. At December 31, 2004, we had total assets of $1.1 billion. Total capitalization was $852.6 million, of which 56% was represented by stockholders equity and 44% by senior debt.

Inflation and Changes in Prices

While the general level of inflation affects certain of our costs, factors unique to the petroleum industry result in independent price fluctuations. Historically, significant fluctuations have occurred in oil and natural gas prices. In addition, changing prices often cause costs of equipment and supplies to vary as industry activity levels increase and decrease to reflect perceptions of future price levels. Although it is difficult to estimate future prices of oil and natural gas, price fluctuations have had, and will continue to have, a material effect on us.

The following table indicates the average oil and natural gas prices received for the years ended December 31, 2004, 2003, and 2002. Average equivalent prices for 2004, 2003, and 2002 were decreased by $4.21, $1.89, and $0.70 per BOE, respectively, as a result of our hedging activities. Average prices per equivalent barrel indicate the composite impact of changes in oil and natural gas prices. Natural gas production is converted to oil equivalents at the conversion rate of six Mcf per Bbl.

	Oil ($/Bbl)	Natural Gas ($/Mcf)	Combined ($/BOE)
Net Price Realization with Hedges			
Year ended December 31, 2004	$ 33.04	$ 5.53	$ 33.07
Year ended December 31, 2003	26.72	4.83	27.14
Year ended December 31, 2002	22.34	3.16	21.72
Average Wellhead Price			
Year ended December 31, 2004	$ 38.24	$ 5.76	$ 37.28
Year ended December 31, 2003	28.82	5.00	29.03
Year ended December 31, 2002	23.38	3.03	22.42

SPECIAL NOTE REGARDING FORWARD-LOOKING STATEMENTS

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

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In particular, forward-looking statements included in this Report relate to, among other things, the following:

- expected capital expenditures and the focus of our capital program;
- areas of future growth;
- our drilling program;
- future horizontal development, secondary development and tertiary recovery potential;
- the implementation of our high-pressure air injection program, the ability to expand the program to other parts of the CCA and the effects thereof;
- the completion of current HPAI projects and the effects thereof;
- anticipated prices for oil and natural gas;
- projected revenues; lifting costs; lease operations expenses; production, ad valorem and severance taxes; DD&A expense; general and administrative expenses; other operating expenses; and taxes;
- timing and amount of future production of oil and natural gas;
- expected hedging positions and payments related to hedging contracts (including the effectiveness thereof);
- expectations regarding working capital, cash flow and anticipated liquidity;
- projected borrowings under our revolving credit facility; and
- marketing of oil and natural gas.

Our actual results may differ significantly from the results discussed in the forward-looking statements. Such statements involve risks and uncertainties, including, but not limited to, the matters discussed in the subsection entitled Factors That May Affect Future Results and Financial Condition below and elsewhere in this Report and our other filings with the Securities and Exchange Commission. If one or more of these risks or uncertainties materialize, or should underlying assumptions prove incorrect, actual outcomes may vary materially from those indicated. We undertake no responsibility to update forward-looking statements for changes related to these or any other factors that may occur subsequent to this filing for any reason.

FACTORS THAT MAY AFFECT FUTURE RESULTS AND FINANCIAL CONDITION

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 and results of operations.

Historically, the markets for oil and natural gas have been volatile, and these markets are likely to continue to be volatile in the future. Our revenues, profitability and future growth depend substantially on prevailing oil and natural gas prices. Lower oil and natural gas prices may reduce the amount of oil and natural gas that we can economically produce. Prevailing oil and natural gas prices also affect the amount of internally generated cash flow available for repayment of indebtedness and capital expenditures. In addition, the amount we can borrow under our revolving credit facility is subject to periodic redetermination based in part on changing expectations of future oil and natural gas prices.

The factors that can cause oil and natural gas price volatility include:

- the supply of domestic and foreign oil and natural gas;
- the ability of members of the Organization of Petroleum Exporting Countries to agree upon and maintain oil prices and production levels;
- political instability or armed conflict in oil or natural gas producing regions;
- the level of consumer demand;
- weather conditions;
- the price and availability of alternative fuels;
- domestic and foreign governmental regulations and taxes;
- domestic political developments; and
- worldwide economic conditions.

The volatile nature of markets for oil and natural gas makes it difficult to reliably estimate future prices. Any decline in oil and natural gas prices adversely affects our financial condition. If oil or natural gas prices decline significantly for a sustained period of time, we may, among other things, be unable to meet our financial obligations, make planned expenditures or raise additional capital.

Reserve estimates depend on many assumptions that may prove to be inaccurate. Any material inaccuracies in our reserve estimates or underlying assumptions could cause the quantities and net present value of our reserves to be overstated.

Estimating quantities of proved oil and natural gas reserves is a complex process that requires interpretations of available technical data and numerous assumptions, including certain economic assumptions. Any significant inaccuracies in these interpretations or assumptions or changes in conditions could cause the quantities and net present value of our reserves to be overstated.

To prepare estimates of economically recoverable oil and natural gas reserves and future net cash flows, we must analyze many variable factors, such as historical production from the area compared with production rates from other producing areas. We must also analyze available geological, geophysical, production and engineering data, and the extent, quality and reliability of this data can vary. The process also involves economic assumptions relating to commodity prices, production costs, severance and excise taxes, capital expenditures and workover and remedial costs. Actual results most likely will vary from our estimates. Any significant variance could reduce the estimated quantities and present value of our reserves.

You should not assume that the present value of future net cash flows from our proved reserves referred to in this Report is the current market value of our estimated oil and natural gas reserves. In accordance with SEC requirements, we base the estimated discounted future net cash flows from our proved reserves on prices and costs in effect on the date of the estimate, holding the prices and costs constant throughout the life of the properties. Actual future prices and costs may differ materially from those used in the net present value estimate, and future net present value estimates using then current prices and costs may be significantly less than the current estimate.

The results of high pressure air injection techniques are uncertain.

We utilize high pressure air injection, or HPAI, techniques on some of our properties and plan to use the techniques in the future on a substantial portion of our properties, including our CCA properties. The additional production and reserves attributable to our use of the 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, our future results of operations and financial condition could be materially adversely affected.

We may be required to take write downs.

We may be required to write down the carrying value of our oil and natural gas properties if (1) future estimated oil and gas prices are low, (2) we have substantial downward adjustments to our estimated proved reserves, (3) our estimates of operating expenses or development costs increase substantially, or (4) 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 and tax rates. Once incurred, a write down of oil and natural gas properties is not reversible at a later date even if oil or gas prices increase.

Our acquisition strategy subjects us to numerous risks that could adversely affect our results of operations.

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. Depending on conditions in the acquisition market, it may be difficult or impossible for us to identify properties for acquisition or we may not be able to make acquisitions on terms that we consider economically acceptable. Even if we are able to identify suitable acquisition opportunities, our acquisition strategy depends upon, among other things, our ability to obtain debt and equity financing and, in some cases, regulatory approvals.

The successful acquisition of producing properties requires an assessment of several factors, including:

- recoverable reserves;
- future oil and natural gas prices;
- operating costs; and
- 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.

Possible future acquisitions could result in our incurring additional debt, contingent liabilities and expenses, all of which could have a material adverse effect on our financial condition and 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.

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 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, 2004, our CCA properties in the Williston Basin represented approximately 66% of our proved reserves and 55% of our 2004 production. Any circumstance or event that negatively impacts production or marketing of oil and natural gas in the Williston Basin could 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 reduce our exposure to fluctuations in the prices of oil and natural gas and to reduce our cash outflows related to interest. Our derivative instruments expose us to risks of financial loss in a variety of circumstances, including when:

- a counterparty to our derivative instruments is unable to satisfy its obligations;
- production is less than expected; or
- there is an adverse change in the expected differential between the underlying price in the derivative instrument and actual prices received for our production.

Derivative instruments may limit our ability to realize increased revenue from increases in the prices for oil and natural gas.

We adopted Statement of Financial Accounting Standards No. 133, Accounting for Derivative Instruments and Hedging Activities (SFAS 133), on January 1, 2001. SFAS 133 generally requires us to record each hedging transaction as an asset or liability measured at its fair value. Each quarter we must record changes in the fair value of our hedges, which could result in significant fluctuations in net income and stockholders equity from period to period.

Drilling oil and natural gas wells is a high-risk activity.

Drilling oil and natural gas wells, including development wells, involves numerous risks, including the risk that no commercially productive oil or natural gas reservoirs will be discovered. We often are uncertain as to the future cost or timing of drilling, completing and producing wells. We may not recover all or any portion of our investment in drilling oil and natural gas wells.

Our drilling operations may be curtailed, delayed or canceled as a result of a variety of factors, including unexpected drilling conditions or miscalculations, title problems, pressure or irregularities in formations, equipment failures or accidents, adverse weather conditions, compliance with environmental and other governmental requirements and cost of, or shortages or delays in the availability of, drilling rigs and equipment.

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.

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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 on 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.

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.

Our business involves many operating risks that can cause substantial losses; insurance may be unavailable or inadequate to protect us against these risks.

Our operations are subject to hazards and risks inherent in drilling for, producing and transporting oil and natural gas, such as: fires; natural disasters; explosions; formations with abnormal pressures; blowouts; collapses of wellbore, casing or other tubulars; failure of oilfield drilling and service tools; uncontrollable flows of oil, natural gas, formation water or drilling fluids; pressure forcing oil or natural gas out of the wellbore at a dangerous velocity coupled with the potential for fire or explosion; changes in below-ground pressure in a formation that cause surface collapse or cratering; pipeline ruptures or cement failures; environmental hazards, such as oil spills, natural gas leaks and discharges of toxic gases; and weather. If any of these events occur, we could incur substantial losses as a result of injury or loss of life; damage to and destruction of property, natural resources and equipment; pollution and other environmental damage; regulatory investigations and penalties; suspension of our operations; and repair and remediation costs.

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 affect on our business.

Our development and exploitation 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 and exploitation projects. 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.

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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 and Chief Executive Officer, Jon S. Brumley, our 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 man 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. If we cannot retain our technical personnel or attract additional experienced technical personnel, our ability to compete could be harmed.

The marketability of our oil and natural gas production is dependent upon transportation facilities over which we have no control.

The marketability of our oil and natural gas production depends in part upon the availability, proximity and capacity of pipelines, oil and natural gas gathering systems and processing facilities. Any significant change in market factors affecting these infrastructure facilities could harm our business. We deliver oil and natural gas through gathering systems and pipelines that we do not own. These facilities may not be available to us in the future.

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, provincial and local laws and regulations, including complex tax and environmental laws and regulations. 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. Under these laws and regulations, we could be liable for personal injuries, property damage, oil spills, discharge of hazardous materials, reclamation costs, remediation and clean-up costs and other environmental damages.

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.

ITEM 7A. ***Quantitative and Qualitative Disclosures About Market Risk***

Hedging policy. We have adopted a formal hedging policy. The purpose of our hedging program is to mitigate the negative effects of declining commodity prices on our business. We plan to continue in the normal course of business to hedge our exposure to fluctuating commodity prices. However, not all of our derivatives qualify for hedge accounting and in some instances management has determined it is more cost effective not to designate certain derivatives as hedges. In very limited circumstances, the Company may enter into derivative financial instruments to achieve other goals besides risk reduction. One example would be the use of a fixed to floating interest rate swap to offset interest expense on fixed rate debt. The Company weighs the increased risk of the instrument versus the potential cash flow savings before entering into any derivative instrument designed to achieve any goal other than risk reduction.

Counterparties. Our counterparties to hedging contracts include: BNP Paribas; Calyon; Deutsche Bank; Mitsui & Co.; Morgan Stanley; Shell Trading; Wachovia; and J. Aron & Company, a wholly-owned subsidiary of Goldman, Sachs & Co. At December 31, 2004 approximately 34%, 24%, 15%, and 15% of estimated hedged oil production was committed to Morgan Stanley, Deutsche Bank, J. Aron & Company, and Calyon, respectively. Approximately 63%, 16%, 11% and 10% of our estimated hedged gas production was contracted with J. Aron & Company, BNP Paribas, Mitsui & Co., and Morgan Stanley, respectively. Performance on all of our contracts with J. Aron & Company is guaranteed by its parent, Goldman, Sachs & Co. We feel the credit-worthiness of our current counterparties is sound and we do not anticipate any non-performance of contractual obligations. As long as each counterparty maintains an investment grade credit rating, pursuant to our hedging contracts, no collateral is required.

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

Commodity price sensitivity. The tables in this section provide information about derivative financial instruments to which we were a party as of December 31, 2004 that are sensitive to changes in oil and natural gas commodity prices.

We hedge commodity price risk with swap contracts, put contracts, and collar contracts. Swap contracts provide a fixed price for a notional amount of sales volumes. Put contracts provide a fixed floor price on a notional amount of sales volumes while allowing full price participation if the relevant index price closes above the floor price. Collar contracts provide a floor price on a notional amount of sales volumes while allowing some additional price participation if the relevant index price closes above the floor price. Additionally, we occasionally sell short put contracts with a strike price well below the floor price of the collar. These short put contracts do not qualify for hedge accounting under SFAS 133, and accordingly, the mark-to-market change in the value of these contracts is recorded as fair value gain/loss in the statements of operations. Thus, not all of our derivatives qualify for hedge accounting and in some instances management has determined it is more cost effective not to designate certain derivatives as hedges. The unrealized mark-to-market loss on our outstanding commodity derivatives at December 31, 2004 was approximately $(58.9) million. As of December 31, 2004, the fair market value of our oil derivative contracts was $(39.4) million and the fair market value of our natural gas derivative contracts was $(13.0) million.

Oil Derivative Contracts at December 31, 2004

Period	Daily Floor Volume (Bbls)	Floor Price (per Bbl)	Daily Cap Volume (Bbls)	Cap Price (per Bbl)	Daily Swap Volume (Bbls)	Swap Price (per Bbl)	Fair Market Value (In thousands)
Jan. - June 2005	15,500	$ 27.55	3,500	$ 31.89	1,000	$ 25.12	$ (10,259)
July - Dec. 2005	12,500	27.84	2,500	31.07	1,000	25.12	(6,810)
Jan. - June 2006	3,000	32.50	1,000	29.88	2,000	25.03	(6,296)
July - Dec. 2006	1,000	27.50	1,000	29.88	2,000	25.03	(6,928)
Jan. - Dec. 2007					2,000	25.11	(9,104)

Natural Gas Derivative Contracts at December 31, 2004

Period	Daily Floor Volume (Mcf)	Floor Price (per Mcf)	Daily Cap Volume (Mcf)	Cap Price (per Mcf)	Daily Swap Volume (Mcf)	Swap Price (per Mcf)	Fair Market Value (In thousands)
Jan. - Dec. 2005	10,000	$ 4.84	5,000	$ 5.97	12,500	$ 4.96	$ (4,998)
Jan. - Dec. 2006	5,000	4.85	5,000	5.68	12,500	5.02	(5,690)
Jan. - Dec. 2007					10,000	4.99	(2,309)

Subsequent to December 31, 2004, we entered into several additional oil and natural gas derivative contracts. We purchased oil put contracts for 4,000 barrels a day with various counterparties at $35.00 for the calendar year 2006 and entered into a basis swap contract for 500 barrels a day for the period of February to December 2005. In addition to the oil contracts, we purchased natural gas put contracts for 7,500 Mcf per day at $5.50 for the period of February 2005 to December 2005.

Interest rate sensitivity. At December 31, 2004, we had total long-term debt of $379.0 million. Of this amount, $150.0 million bears interest at a fixed rate of $8^{3}/8$%, and $150.0 million bears at a fixed rate of $6^{1}/4$%. The remaining outstanding long-term debt balance of $79.0 million is under our credit agreement and is subject to floating market rates of interest. Borrowings under the credit agreement bear interest at a fluctuating rate that is linked to LIBOR. As of December 31, 2004, we had one outstanding interest rate swap. This swap does not qualify for hedge accounting as it swaps a fixed interest rate for a floating interest rate tied to LIBOR. The following table summarizes the terms of this swap:

Interest Rate Derivative Contract at December 31, 2004

Notional Swap Amount	Start Date	End Date	Encore Pays	Encore Receives	Fair Market Value at December 31, 2004 (In thousands)
(In thousands)					
$80,000	June 25, 2002	June 15, 2005	LIBOR + 3.89%	8.375%	$ 462

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GLOSSARY OF OIL AND NATURAL GAS TERMS

The following are abbreviations and definitions of certain terms commonly used in the oil and natural gas industry and this 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 at standard atmospheric conditions.

Bbl/ D. One stock tank barrel of oil or other liquid hydrocarbons 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 barrel of oil equivalent per day, calculated by converting natural gas to oil equivalent barrels at a ratio of six Mcf to one Bbl of oil.

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 or in close proximity to an area of known production targeting existing reservoirs.

Exploratory Well. A well drilled to find and produce oil or natural gas in an unproved area or to find a new reservoir in a field previously found to be productive of oil or natural gas in another reservoir.

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). High-pressure air injection 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. All direct and 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.

MBbl. One thousand barrels of oil or other liquid hydrocarbons.

MBOE. One thousand barrels of oil equivalent, calculated by converting gas to oil equivalent barrels at a ratio of six Mcf to one Bbl of oil.

Mcf. One thousand cubic feet of natural gas.

Mcf/ D. One thousand cubic feet of natural gas per day.

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

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

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 cubic feet of natural gas.

Net Acres or Net Wells. Gross acres or wells multiplied, as the case may be, 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 taxes and lease operating expense.

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%.

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.

Reserve-To-Production Index or 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.

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% per annum to reflect the timing of future cash flows. Standardized measure differs from PV-10 because standardized measure includes the effect of asset retirement obligations and 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.

Item 8. ***Financial Statements and Supplementary Data***

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REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

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

We have audited the accompanying consolidated balance sheets of Encore Acquisition Company and subsidiaries (the Company) as of December 31, 2004 and 2003, and the related consolidated statements of operations, stockholders equity, and cash flows for each of the years in the three-year period ended December 31, 2004. These financial statements are the responsibility of the Company s management. Our responsibility is to express an opinion on these financial statements based on our audits.

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

In our opinion, the consolidated financial statements referred to above present fairly, in all material respects, the consolidated financial position of the Company at December 31, 2004 and 2003, and the consolidated results of its operations and its cash flows for each of the years in the three-year period ended December 31, 2004, in conformity with U.S. generally accepted accounting principles.

As explained in Note 2 to the consolidated financial statements, effective January 1, 2003, the Company adopted Statement of Financial Accounting Standards No. 143, Accounting for Asset Retirement Obligations.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the effectiveness of the Company s internal control over financial reporting as of December 31, 2004, based on the criteria established in *Internal Control Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission, and our report dated March 7, 2005 expressed an unqualified opinion thereon.

/s/ Ernst & Young LLP

Fort Worth, Texas
March 7, 2005

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ENCORE ACQUISITION COMPANY
CONSOLIDATED BALANCE SHEETS

	December 31, 2004	December 31, 2003
	(In thousands except share data)	
ASSETS		
Current assets:		
Cash and cash equivalents	$ 1,103	$ 431
Accounts receivable	43,839	27,640
Inventory	6,550	6,019
Derivatives	2,665	5,588
Deferred taxes	11,118	3,592
Other	5,842	1,673
Total current assets	71,117	44,943
Properties and equipment, at cost successful efforts method:		
Proved properties	1,134,220	739,288
Unproved properties	29,740	921
Accumulated depletion, depreciation, and amortization	(171,691)	(124,646)
	992,269	615,563
Other property and equipment	10,425	3,831
Accumulated depreciation	(3,551)	(2,586)
	6,874	1,245
Goodwill	37,995	
Other	15,145	10,387
Total assets	$ 1,123,400	$ 672,138
LIABILITIES AND STOCKHOLDERS EQUITY		
Current liabilities:		
Accounts payable	$ 24,375	$ 10,668
Accrued lease operations expense	3,408	2,507
Accrued development capital	14,643	9,302
Derivatives	24,270	8,026
Production and severance taxes payable	9,106	5,365
Other	10,881	9,127
Total current liabilities	86,683	44,995

Derivatives	31,477	3,514
Future abandonment cost	6,601	5,341
Deferred taxes	146,064	80,313
Long-term debt	379,000	179,000
Total liabilities	649,825	313,163
Commitments and contingencies		
Stockholders equity:		
Preferred stock, $.01 par value, 5,000,000 shares authorized, none issued and outstanding		
Common stock, $.01 par value, 60,000,000 shares authorized, 32,654,798 and 30,335,693 issued and outstanding	327	303
Additional paid-in capital	314,736	253,865
Deferred compensation	(4,603)	(2,528)
Retained earnings	199,512	117,365
Accumulated other comprehensive income	(36,397)	(10,030)
Total stockholders equity	473,575	358,975
Total liabilities and stockholders equity	$ 1,123,400	$ 672,138

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

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ENCORE ACQUISITION COMPANY
CONSOLIDATED STATEMENTS OF OPERATIONS

	Year Ended December 31,		
	2004	2003	2002
	(In thousands except per share data)		
Revenues:			
Oil	$ 220,649	$ 176,351	$ 134,854
Natural gas	77,884	43,745	25,838
Total revenues	298,533	220,096	160,692
Expenses:			
Production			
Lease operations	47,142	37,846	30,678
Production, ad valorem, and severance taxes	30,313	22,013	15,653
Depletion, depreciation, and amortization	48,522	33,530	34,550
Exploration	3,907		
General and administrative (excluding non-cash stock based compensation)	10,982	8,680	6,150
Non-cash stock based compensation	1,770	614	
Derivative fair value (gain) loss	5,011	(885)	(900)
Other operating	5,028	3,481	2,045
Total expenses	152,675	105,279	88,176
Operating income	145,858	114,817	72,516
Other income (expenses):			
Interest	(23,459)	(16,151)	(12,306)
Other	240	214	91
Total other income (expenses)	(23,219)	(15,937)	(12,215)
Income before income taxes and cumulative effect of accounting change	122,639	98,880	60,301
Current income tax benefit (provision)	(1,913)	(991)	745
Deferred income tax provision	(38,579)	(35,111)	(23,361)
Income before cumulative effect of accounting change	82,147	62,778	37,685
Cumulative effect of accounting change, net of income taxes		863	
Net income	$ 82,147	$ 63,641	$ 37,685
Income before cumulative effect of accounting change per common share:			

Basic	$ 2.62	$ 2.09	$ 1.25
Diluted	2.58	2.07	1.25
Net income per common share:			
Basic	$ 2.62	$ 2.11	$ 1.25
Diluted	2.58	2.10	1.25
Weighted average common shares outstanding:			
Basic	31,393	30,102	30,031
Diluted	31,825	30,333	30,161

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

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ENCORE ACQUISITION COMPANY
CONSOLIDATED STATEMENT OF STOCKHOLDERS EQUITY

	Shares of Common Stock	Common Stock	Additional Paid-In Capital	Treasury Stock	Deferred Compensation	Retained Earnings (Deficit)	Accumulated Other Comprehensive Income	Total Stockholders Equity
	(In thousands except share data)							
Balance at December 31, 2001	30,030	$ 300	$ 248,786	$	$	$ 16,039	$ 4,177	$ 269,302
Exercise of stock options	4		51					51
Issuance of restricted stock	129	2	2,394		(2,396)			
Components of comprehensive income:								
Net income						37,685		37,685
Change in deferred hedge gain/loss (Net of income taxes of $6,602)							(10,772)	(10,772)
Total comprehensive income								26,913
Balance at December 31, 2002	30,163	302	251,231		(2,396)	53,724	(6,595)	296,266
Exercise of stock options	145	1	1,974					1,975
Issuance of Common Stock	9,060	91	175,383					175,474
Purchase of Treasury Stock				(175,560)				(175,560)
Cancellation of Treasury Stock	(9,060)	(91)	(175,469)	175,560				
Deferred compensation:								
Issuance of restricted Common Stock	45		927		(927)			
Amortization of expense					614			614

Other changes	(17)		(181)		181			
Components of comprehensive income:								
Net income						63,641		63,641
Change in deferred hedge gain/loss (Net of income taxes of $2,105)							(3,435)	(3,435)
Total comprehensive income								60,206
Balance at December 31, 2003	30,336	303	253,865		(2,528)	117,365	(10,030)	358,975
Exercise of stock options	202	2	4,119					4,121
Issuance of Common Stock	2,000	20	52,909					52,929
Deferred compensation:								
Issuance of restricted Common Stock	126	2	3,371		(3,373)			
Amortization of expense					1,770			1,770
Other changes	(9)		472		(472)			
Components of comprehensive income:								
Net income						82,147		82,147
Change in deferred hedge gain/loss (Net of income taxes of $15,757)							(26,367)	(26,367)
Total comprehensive income								55,780
Balance at December 31, 2004	32,655	$ 327	$ 314,736	$	$ (4,603)	$ 199,512	$ (36,397)	$ 473,575

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

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ENCORE ACQUISITION COMPANY
CONSOLIDATED STATEMENTS OF CASH FLOWS

	Year Ended December 31,		
	2004	2003	2002
	(In thousands)		
Operating activities			
Net income	$ 82,147	$ 63,641	$ 37,685
Adjustments to reconcile net income to net cash provided by operating activities:			
Depletion, depreciation, and amortization	48,522	33,530	34,550
Dry hole expense	2,086		
Deferred taxes	38,579	35,111	23,361
Non-cash stock based compensation	1,770	614	
Cumulative effect of accounting change		(863)	
Non-cash derivative fair value (gain) loss	12,449	(165)	(1,239)
Other non-cash	1,456	1,293	177
Loss on disposition of assets	271	322	254
Changes in operating assets and liabilities:			
Accounts receivable	(10,719)	(5,602)	(5,695)
Other current assets	(7,220)	(8,592)	(3,161)
Other assets	(5,568)	(2,024)	2,177
Accounts payable and other current liabilities	8,048	6,553	3,400
Cash provided by operating activities	171,821	123,818	91,509
Investing activities			
Proceeds from disposition of assets	703	1,295	226
Purchases of other property and equipment	(7,594)	(1,464)	(680)
Acquisition of oil and natural gas properties	(116,316)	(54,601)	(78,549)
Acquisition of Cortez Oil & Gas, Inc. (net of cash acquired)	(123,808)		
Development of oil and natural gas properties	(186,455)	(98,977)	(80,313)
Cash used by investing activities	(433,470)	(153,747)	(159,316)
Financing activities			
Proceeds from issuance of common stock	53,900	176,127	
Purchase of treasury stock		(175,560)	
Offering costs paid	(971)	(653)	
Proceeds from issuance of $8^3/8$% notes			150,000
Proceeds from issuance of $6^1/4$% notes	150,000		
Payments for debt issuance costs	(4,808)	(125)	(6,195)
Exercise of stock options	2,756	1,975	51
Proceeds from long-term debt	328,500	112,500	144,000
Payments on long-term debt	(278,500)	(99,500)	(206,000)
Cash overdrafts	11,444	2,539	
Payments on note payable			(1,107)

Cash provided by financing activities	262,321	17,303	80,749
Increase (decrease) in cash and cash equivalents	672	(12,626)	12,942
Cash and cash equivalents, beginning of period	431	13,057	115
Cash and cash equivalents, end of period	$ 1,103	$ 431	$ 13,057

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

ENCORE ACQUISITION COMPANY
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

1. Formation of the Company and Basis of Presentation

Encore Acquisition Company, a Delaware corporation (Encore or the Company), is a growing independent energy company engaged in the acquisition, development, exploitation, exploration, and production of onshore North American oil and natural gas reserves. Since the Company s inception in 1998, Encore has sought to acquire high-quality assets with potential for upside through low-risk development drilling projects. Encore s properties are currently located in four core areas: the Cedar Creek Anticline (CCA) in the Williston Basin of Montana and North Dakota; the Permian Basin of West Texas and Southeastern New Mexico; the Mid-Continent area, which includes the Arkoma and Anadarko Basins of Oklahoma, the ArkLaTx region of northern Louisiana and east Texas and the Barnett Shale of north Texas; and the Rockies, which includes non-CCA assets in the Williston and Powder River Basins of Montana, and the Paradox Basin of southeastern Utah.

2. Summary of Significant Accounting Policies

Principles of Consolidation

Our consolidated financial statements include the accounts of all of our subsidiaries. All material intercompany balances and transactions are eliminated.

Cash and Cash Equivalents

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

Inventories

Inventories are comprised principally of materials and supplies, which are stated at the lower of cost (determined on an average basis) or market, and oil in pipelines. Oil produced at the lease which resides unsold in pipelines is carried at an amount equal to its operating costs to produce.

Properties and Equipment

Oil and Natural Gas Properties

The Company utilizes the successful efforts method of accounting for its oil and gas properties. Under this method, all costs associated with productive and nonproductive development wells are capitalized. Exploration expenses, including geological and geophysical expenses and delay rentals, are charged to expense as incurred. Costs associated with exploratory wells are initially capitalized pending determination of whether the well is economically productive or nonproductive.

All capitalized costs associated with both development and exploratory wells are shown as Development of oil and natural gas properties in the Investing activities section of the Consolidated Statement of Cash Flows. If an exploratory well does not find reserves or does not find reserves in a sufficient quantity as to make them economically producible, the previously capitalized costs are expensed in the Consolidated Statement of Operations and shown as a non-cash adjustment to net income in the Operating activities section of the Consolidated Statement of Cash Flows in the period in which the determination was made. If a determination cannot be made within one year of the exploration well being drilled and no other drilling or exploration activities to evaluate the discovery are firmly planned, all previously capitalized costs associated with the exploratory well are expensed and shown as a non-cash adjustment to net income at that time. Expenditures for redrilling or directional drilling in a previously

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ENCORE ACQUISITION COMPANY
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

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

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

Additionally, the Company s independent reserve engineers estimate our reserves once a year at December 31. This results in a new DD&A rate which the Company uses for the preceding fourth quarter after adjusting for fourth quarter production.

Unproved Properties

The Company adheres to Statement of Financial Accounting Standards No. 19, Financial Accounting and Reporting by Oil and Gas Producing Companies, for recognizing any impairment of capitalized costs to unproved properties. The greatest portion of these costs generally relate to the acquisition of leasehold costs. The costs are capitalized and periodically evaluated as to recoverability, based on changes brought about by economic factors and potential shifts in business strategy employed by management. The Company considers a combination of time and geologic and engineering factors to evaluate the need for impairment of these costs. Unproved properties had a net book value of $29.7 million and $0.9 million as of December 31, 2004 and 2003, respectively. The Company recorded a charge for unproved acreage impairment in the amount of $0.7 million, $0.4 million, and zero in 2004, 2003, and 2002, respectively.

Other Property and Equipment

Other property and equipment are carried at cost. Depreciation and amortization are provided on a straight-line basis over their estimated useful lives, which range from three to ten years.

Goodwill

Goodwill represents the excess of the purchase price over the estimated fair value of the net assets acquired in the purchase of Cortez Oil & Gas, Inc. in April 2004 (see Note 3. Acquisitions). The Company tests goodwill for impairment quarterly by applying a fair-value based test. The Company would recognize an impairment charge for any amount by which the carrying amount of goodwill exceeds its fair value. The Company tested goodwill for impairment and used discounted cash flows to establish fair values for the Company as a whole. The test indicated no impairment for 2004.

Capitalization of Interest

The Company does not capitalize interest related to our unevaluated oil and natural gas properties or any other long-lived assets.

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ENCORE ACQUISITION COMPANY
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Impairment

The Company is required to assess the need for an impairment of capitalized costs of oil and natural gas properties and other long-lived assets. The Company tests for impairment on a quarterly basis. If impairment is indicated based on a comparison of the asset s carrying value to its undiscounted expected future net cash flows, then it is recognized to the extent that the carrying value exceeds fair value. Any impairment charge incurred is expensed reduces our recorded basis in the asset.

Asset Retirement Obligations

Effective January 1, 2003, the Company adopted SFAS No. 143, *Accounting for Asset Retirement Obligations.* This statement applies to obligations associated with the retirement of tangible long-lived assets that result from the acquisition, construction and development of the assets.

SFAS 143 requires that the fair value of a liability for a retirement obligation be recognized in the period in which the liability is incurred. For oil and gas properties, this is the period in which an oil or gas well is acquired or drilled. The asset retirement obligation is capitalized as part of the carrying amount of our oil and gas properties at its discounted fair value. The liability is then accreted each period until the liability is settled or the well is sold, at which time the liability is reversed. Estimates are based on historical experience in plugging and abandoning wells and estimated remaining lives of those wells based on reserve estimates. The Company does not provide for a market risk premium associated with asset retirement obligations because a reliable estimate cannot be determined. See Note 5, Asset Retirement Obligations for more detail.

Stock-based Compensation

Employee stock options and restricted stock awards are accounted for under the provisions of Accounting Principles Board Opinion No. 25, Accounting for Stock Issued to Employees (APB 25). Accordingly, no compensation is recorded for stock options that are granted to employees or non-employee directors with an exercise price equal to or above the common stock price on the grant date. However, expense is recorded related to restricted stock granted to employees. See Note 11. Employee Benefit Plans for more information.

If compensation expense for the stock based awards had been determined using the provisions of Statement of Financial Accounting Standard No. 123, Accounting for Stock-Based Compensation (SFAS 123), the Company s net income and net income per share would have been adjusted to the pro forma amounts indicated below (in thousands, except per share amounts):

	Year Ended December 31,		
	2004	**2003**	**2002**
As Reported:			
Non-cash stock based compensation (net of taxes)	$ 1,108	$ 381	$
Net income	82,147	63,641	37,685
Basic net income per share	2.62	2.11	1.25
Diluted net income per share	2.58	2.10	1.25
Pro Forma:			
Non-cash stock based compensation (net of taxes)	$ 2,289	$ 1,929	$ 1,277
Net income	80,966	62,093	36,408
Basic net income per share	2.58	2.06	1.21
Diluted net income per share	2.54	2.05	1.21

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ENCORE ACQUISITION COMPANY
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

During the year ended December 31, 2004, 6,509 employee stock options and 9,236 shares of restricted stock that were issued and outstanding at December 31, 2003 were forfeited.

Under SFAS 123, the fair value of each stock option grant is estimated on the date of grant using the Black-Scholes option-pricing model. The following amounts represent weighted average values used in the model to calculate the fair value of the options granted during 2004, 2003, and 2002:

	Year Ended December 31,		
	2004	**2003**	**2002**
Risk free interest rate	3.2%	3.0%	3.4%
Expected life	6 years	4 years	4 years
Expected volatility	34.8%	36.5%	46.7%
Expected dividend yield	0.0%	0.0%	0.0%

Segment Reporting

The Company has only one operating segment, the development and exploitation of oil and natural gas reserves. Additionally, all of our assets are located in the United States and all of our oil and natural gas revenues are derived from customers located in the United States.

In 2004, 29% and 27% of total oil and natural gas production was sold to Shell, and ConocoPhillips, respectively. In 2003, 28%, 26%, and 11% of total oil and natural gas production was sold to ConocoPhillips, Shell, and Eighty-Eight Oil, respectively. In 2002, ConAgra and Equiva Trading Company (a joint venture between Shell and Texaco) accounted for 16% and 10% of total oil and natural gas sales, respectively.

Income Taxes

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

Revenue Recognition

Revenues are recognized for the Company s share of jointly owned properties as oil and natural gas is produced and sold, net of royalties and net profits interest payments. Revenues are also reduced by any processing and other fees paid, except for transportation costs paid to third parties which are recorded as expense. Natural gas revenues are recorded using the sales method of accounting, whereby revenue is recognized as natural gas is sold rather than as produced. Royalties, net profits interests, and severance taxes are paid based upon the actual price received from the sales. To the extent actual quantities and values of oil and natural gas are unavailable for a given reporting period because of timing or information not received from third parties, we estimate and record the expected sales volumes and values for those properties. The Company also does not recognize revenue for the production in tanks or pipelines that has not been delivered to the purchaser. The Company s net oil inventories in pipelines were 43,010 Bbls and 46,622 Bbls at December 31, 2004 and 2003, respectively. Natural gas imbalances under-delivered to the Company at December 31, 2004 and December 31, 2003, were 540,000 MMBTU and 446,000 MMBTU, respectively.

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ENCORE ACQUISITION COMPANY
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Shipping Costs

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

Hedging and Related Activities

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

Statement of Financial Accounting Standards No. 133, Accounting for Derivative Instruments and Hedging Activities (SFAS 133) requires us to recognize all of our derivative financial instruments in our consolidated balance sheets as either assets or liabilities and measure them at fair value. If a derivative does not qualify for hedge accounting, it must be adjusted to fair value through earnings. However, if a derivative does qualify for hedge accounting, depending on the nature of the hedge, changes in fair value can be offset against the change in fair value of the hedged item through earnings or recognized in other comprehensive income until such time as the hedged item is recognized in earnings.

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

Currently, all of our derivative financial instruments that are designated as hedges are designated as cash flow hedges. These instruments hedge the exposure of variability in expected future cash flows that is attributable to a particular risk. The effective portion of the mark-to-market gain or loss on these derivative instruments is recorded in other comprehensive income in stockholders equity and reclassified into earnings in the same period in which the hedged transaction affects earnings. Any ineffective portion of the mark-to-market gain or loss is recognized into earnings immediately.

Comprehensive Income

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

Use of Estimates

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

Estimates made in preparing these consolidated financial statements include the Company s estimated proved oil and natural gas reserve volumes used in calculating depletion, depreciation, and amortization expense; the estimated future cash flows and fair value of our properties used in determining the need for any impairment write-down; and the timing and amount of future abandonment costs used in calculating the Company s asset retirement obligations. See Note 5. Asset Retirement Obligations. Future changes in the assumptions used could have a significant impact on reported results in future periods.

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ENCORE ACQUISITION COMPANY
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

New Accounting Standards

In December 2004, the FASB issued Statement No. 123 (revised 2004), Share-Based Payment (SFAS 123(R)), which replaces SFAS 123, Accounting for Stock-Based Compensation, and supersedes APB 25. SFAS 123(R) requires the measurement of all share-based payments to employees, including grants of employee stock options, using a fair-value-based method and the recording of expense in our Consolidated Statements of Operations. The accounting provisions of SFAS 123(R) are effective for reporting periods beginning after June 15, 2005. We are required to adopt SFAS 123(R) in the third quarter of 2005. The pro forma disclosures previously permitted under SFAS 123 no longer will be an alternative to financial statement recognition. See Stock-based Compensation above for the pro forma net income and net income per share amounts, for fiscal 2002 through fiscal 2004, as if we had used a fair-value-based method similar to the methods required under SFAS 123(R) to measure compensation expense for employee stock incentive awards.

In December 2004, the FASB issued FASB Staff Position No. FAS 109-1 (FAS 109-1), Application of FASB Statement No. 109, Accounting for Income Taxes, to the Tax Deduction on Qualified Production Activities Provided by the American Jobs Creation Act of 2004. The American Jobs Creation Act of 2004 (the AJCA) introduces a special 9% tax deduction on qualified production activities. FAS 109-1 clarifies that this tax deduction should be accounted for as a special tax deduction in accordance with Statement 109. Pursuant to the AJCA, Encore will not be able to claim this tax benefit until the first quarter of fiscal 2006. We do not expect the adoption of these new tax provisions to have a material impact on our consolidated financial position, results of operations or cash flows.

3. Acquisitions

2002 Acquisitions

On January 4, 2002, we closed the purchase of our Central Permian properties. These properties were purchased from Conoco for approximately $50.1 million. The properties include two major operated fields: East Cowden Grayburg and Fuhrman-Nix; and two non-operated fields: North Cowden and Yates. During the second quarter of 2002, we closed a second follow-on acquisition of additional working interests in the East Cowden Field for $8.3 million.

On August 29, 2002, we completed an acquisition of interests in oil and natural gas properties in southeast Utah s Paradox Basin. The final purchase price after the exercise of preferential rights was $17.9 million ($16.7 million after closing adjustments). The properties are divided between two oil-producing units: the Ratherford Unit operated by ExxonMobil and the Aneth Unit operated by Resolute Natural Resources Company.

2003 Acquisitions

On July 31, 2003, the Company purchased interests in natural gas properties in North Louisiana (the Elm Grove acquisition) from a group of private sellers at a cost of $54.6 million. Subsequently, we have purchased several smaller interests in these properties. The original purchase was effective June 1, 2003. Beginning August 1, 2003, revenues and expenses from these properties have been included in the Company s Consolidated Statements of Operations and drilling costs have been included in Development of oil and natural gas properties in the Consolidated Statements of Cash Flows. From June 1, 2003 to July 31, 2003, revenues, expenses, and development capital of the properties were treated as adjustments to the purchase price. The properties are located in the Elm Grove Field in Bossier Parish, Louisiana and are non-operated working interests ranging from 1% to 47% across 1,800 net acres in 15 sections.

These acquisitions have been accounted for as purchases. The operating results of the acquired properties have been included in our consolidated financial statements since the date of acquisition.

ENCORE ACQUISITION COMPANY
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

2004 Acquisitions

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

The acquired oil and natural gas properties are located primarily in the CCA of Montana, the Permian Basin of West Texas and Southeastern New Mexico and in the Mid-Continent area, including the Anadarko and Arkoma Basins of Oklahoma and the Barnett Shale north of Fort Worth, Texas. Cortez operating results are included in the Company s Consolidated Statement of Operations beginning on April 1, 2004.

The calculation of the total purchase price and the estimated allocation as of December 31, 2004 to the fair value of net assets acquired at April 14, 2004, are as follows (in thousands):

Calculation of total purchase price:		
Cash paid to Cortez former owners	$	85,805
Cortez debt repaid		39,449
Transaction costs		1,760
Total purchase price	$	127,014
Allocation of purchase price to the fair value of net assets acquired:		
Cash	$	3,206
Current assets, excluding cash		5,880
Proved oil and gas properties		120,503
Unproved oil and gas properties		3,011
Goodwill		37,995
Total assets acquired		170,595
Current liabilities		(5,694)
Non-current liabilities		(996)
Deferred income taxes		(36,891)
Total liabilities assumed		(43,581)
Fair value of net assets acquired	$	127,014

The purchase price allocation resulted in $38.0 million of goodwill primarily as the result of the difference between the fair value of acquired oil and gas properties and their lower carryover tax basis, which resulted in deferred taxes of $36.9 million. Management believes the goodwill will be recovered through operating synergies resulting from the close proximity of the properties acquired to our existing operations, particularly the additional interest in the CCA and Permian properties acquired through the Cortez acquisition. None of the goodwill is deductible for income tax purposes.

Overton. On June 17, 2004, we completed the acquisition of natural gas producing properties and undeveloped leases in the Overton Field located in Smith County, Texas for $83.1 million. The Overton Field assets are in the same core area as our interests in Elm Grove Field and have similar geology. Overton operating results are included in our consolidated statement of operations for the period July through December 2004.

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ENCORE ACQUISITION COMPANY
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

4. Commitments and Contingencies

Leases

We lease office space and equipment that have remaining non-cancelable lease terms in excess of one year. The following table summarizes by year our remaining non-cancelable future payments under operating leases as of December 31, 2004 (in thousands):

2005	$ 1,329
2006	1,434
2007	1,498
2008	1,509
2009	1,393
Thereafter	5,398

Our operating lease rental expense was approximately $3.5 million, $1.5 million, and $0.9 million in 2004, 2003, and 2002, respectively.

5. Asset Retirement Obligations

In August 2001, the FASB issued SFAS 143, which the Company adopted as of January 1, 2003. This statement requires us to record a liability in the period in which an asset retirement obligation (ARO) is incurred. Also, upon initial recognition of the liability, we must capitalize additional asset cost equal to the amount of the liability. In addition to any obligations that arise after the effective date of SFAS 143, upon initial adoption we must recognize (1) a liability for any existing AROs, (2) capitalized cost related to the liability, and (3) accumulated depletion, depreciation, and amortization on that capitalized cost.

The adoption of SFAS 143 resulted in a January 1, 2003 cumulative effect of accounting change adjustment to record (1) a $4.0 million increase in the carrying values of proved properties, (2) a $2.1 million decrease in accumulated depletion, depreciation, and amortization, and (3) a $5.2 million increase in other non-current liabilities, and (4) a gain of $0.9 million, net of tax, as a cumulative effect of accounting change on January 1, 2003. The Company does not include a market risk premium in its risk estimates as the effect would not be material.

The following table shows net income and basic and diluted net income per common share as reported, as well as pro forma amounts as if the Company had adopted SFAS 143 prior to January 1, 2001 (in thousands, except per common share amounts):

	Year Ended December 31,		
	2004	2003	2002
As Reported:			
Net income	$ 82,147	$ 63,641	$ 37,685
Basic net income per common share	2.62	2.11	1.25
Diluted net income per common share	2.58	2.10	1.25
Pro Forma:			
Net income	$ 82,147	$ 62,778	$ 38,035
Basic net income per common share	2.62	2.09	1.27
Diluted net income per common share	2.58	2.07	1.26

The Company s primary asset retirement obligations relate to future plugging and abandonment expenses on our oil and natural gas properties and related facilities disposal. As of December 31, 2004, the

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ENCORE ACQUISITION COMPANY
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Company had $3.3 million held in an escrow account from which funds are released only for reimbursement of plugging and abandonment expenses on our Bell Creek property. This amount is included in Other assets in the accompanying Consolidated Balance Sheet. The following table summarizes the changes in the Company s future abandonment liability recorded in Future abandonment cost on the Company s Consolidated Balance Sheet for the period from January 1, 2003 through December 31, 2004 (in thousands):

	Year Ended December 31, 2004	Year Ended December 31, 2003
Future abandonment liability at January 1	$ 5,341	$ 4,791
Acquisition of properties	1,165	337
Wells drilled	467	83
Accretion expense	317	272
Plugging and abandonment costs incurred	(280)	(100)
Revision of estimates	(409)	(42)
Future abandonment liability at December 31	$ 6,601	$ 5,341

The pro-forma asset retirement obligation as of December 31, 2001 would have been $4.1 million, had the Company previously adopted SFAS 143 prior to January 1, 2001.

6. Accounts Payable and Accrued Liabilities

Other current liabilities were as follows at December 31 (in thousands):

	2004	2003
Oil and natural gas revenue payable	$ 2,413	$ 1,176
Net profits payable	558	589
Interest	2,630	563
Other	5,280	6,799
Total	$ 10,881	$ 9,127

7. Indebtedness

The following table details the Company s indebtedness at December 31 (in thousands):

	2004	2003
Revolving Credit Facility	$ 79,000	$ 29,000
$6^1/4$% Notes	150,000	
$8^3/8$% Notes	150,000	150,000
Total	$ 379,000	$ 179,000

Senior Subordinated Notes

On June 25, 2002, the Company sold $150 million of $8^3/8$% Senior Subordinated Notes maturing on June 15, 2012 (the $8^3/8$% Notes). The offering was made through a private placement pursuant to Rule 144A. Subsequently, the Company filed a registration statement on Form S-4/A, which was declared effective on December 6, 2002. The Company received net proceeds of $145.6 million from the sale of the $8^3/8$% Notes, after deducting debt issuance costs. The proceeds were used to repay and retire the

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ENCORE ACQUISITION COMPANY
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Company s prior credit facility ($143.0 million), to pay the fees and expenses related to a new revolving credit facility ($1.5 million), and to hold in reserve for the Paradox Basin acquisition ($1.1 million).

On April 2, 2004, the Company issued $150.0 million of 6 1/4% Senior Subordinated Notes due April 15, 2014 (the 6 1/4% Notes and together with the 8 3/8% Notes, the Notes). The Company received net proceeds of approximately $146.4 million after paying all costs associated with the offering. The net proceeds were used to fund the acquisition of Cortez Oil & Gas, Inc. and repay amounts outstanding under our revolving credit facility. The offering was made through a private placement. The 6 1/4% Notes were resold by the initial purchasers in transactions exempt from registration under Rule 144A and Regulation S. The privately placed notes were subsequently exchanged for registered notes with substantially identical terms.

Interest on the 6 1/4% Notes is paid semi-annually on April 15 and October 15. The indenture governing the 6 1/4% Notes contains certain affirmative, negative, and financial covenants, which include limitations on incurrence of additional debt, restrictions on asset dispositions and restricted payments, maintenance of a 1.0 to 1.0 current ratio, and maintenance of EBITDA, as defined, to interest expense ratio of 2.5 to 1.0. As of December 31, 2004, the Company was in compliance with all covenants in the indenture.

All of the Company s subsidiaries are currently subsidiary guarantors of the Notes. Since (1) each subsidiary guarantor is 100% owned by the Company, (2) the Company has no assets or operations that are independent of its subsidiaries, (3) the subsidiary guarantees are full and unconditional and joint and several and (4) all of the Company s subsidiaries are subsidiary guarantors, the Company has not included the financial statements of each subsidiary in this report. The subsidiary guarantors may without restriction transfer funds to the Company in the form of cash dividends, loans and advances.

Revolving Credit Facility

On August 19, 2004, the Company entered into an amended and restated five-year senior secured revolving credit facility with a bank syndicate comprised of Bank of America, N.A. and other lenders. Availability under the amended and restated credit facility is determined through semi-annual borrowing base determinations and may be increased or decreased. The initial borrowing base is $400 million and may be increased to up to $750 million. The amended and restated credit facility matures on August 19, 2009. The amended and restated credit facility replaced the Company s previous $300 million credit facility, which would have matured in June 2006.

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

Amounts outstanding under the amended and restated credit facility are subject to varying rates of interest based on (1) the amount outstanding under the amended and restated credit facility in relation to the borrowing base and (2) whether the loan is a Eurodollar loan or a base rate loan. The following table summarizes the calculation of the various interest rates for both Eurodollar and base rate loans:

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

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ENCORE ACQUISITION COMPANY
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

(b) The Base Rate is calculated as the highest of (1) the annual rate of interest announced by Bank of America, N.A. as its prime rate and (2) the federal funds effective rate plus 0.5%.

The borrowing base will be redetermined each June 1 and December 1, commencing June 1, 2005. The bank syndicate has the ability to request one additional borrowing base redetermination per year, and the Company is permitted to request two additional borrowing base redeterminations per year. Generally, if amounts outstanding ever exceed the borrowing base, the Company must reduce the amounts outstanding to the redetermined borrowing base within six months, provided that if amounts outstanding exceed the borrowing base as a result of any sale of the Company s assets or permitted subordinated debt, the Company must reduce the amounts outstanding immediately upon consummation of the sale.

Borrowings under the amended and restated credit facility may be repaid from time to time without penalty.

The amended and restated credit facility contains certain affirmative, negative, and financial covenants; which include, but not limited to, (1) limitations on the incurrence of additional debt, payment of dividends, repurchases of the Company s common stock, asset dispositions and restricted payments, (2) maintenance of a 1.0 to 1.0 current ratio, and (3) maintenance of EBITDA, as defined, to interest expense ratio of 2.5 to 1.0. As of December 31, 2004, the Company was in compliance with all covenants in the amended and restated credit facility.

As of December 31, 2004, The Company had $79.0 million outstanding under the facility. This reflects an increase of $50.0 million to the outstanding balance under the facility at December 31, 2003.

The Company incurs a commitment fee on the unused portion of the facility determined based on the ratio of borrowings to the borrowing base in effect on such date. The following table summarizes the calculation of the Company s commitment fee:

Borrowings to Borrowing Base	**Commitment Fee Percentage**
<0.40 to 1	0.250%
≥0.40 to 1< 0.90 to 1	0.375%
≥0.90 to 1	0.500%

During 2004 and 2003, the weighted average interest rates for our revolving credit facilities were 6.6% and 7.2%, respectively.

Letters of Credit

The Company had $30.4 million and zero of outstanding letters of credit at December 31, 2004 and 2003, respectively. These letters of credit are posted primarily with two counterparties to the Company s commodity derivative contracts and are used in lieu of cash margin deposits with those counterparties.

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ENCORE ACQUISITION COMPANY
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Long-Term Debt Maturities

The following table illustrates the Company s long-term debt maturities at December 31, 2004 (in thousands):

	Payments Due by Period				
	Total	2005	2006-2007	2008-2009	Thereafter
8 3/8% Notes	$ 150,000	$	$	$	$ 150,000
6 1/4% Notes	150,000				150,000
Revolving credit facility	79,000			79,000	
Totals	$ 379,000	$	$	$ 79,000	$ 300,000

Consolidated cash payments for interest were $21.4 million, $16.2 million, and $13.2 million, respectively, for 2004, 2003, and 2002.

During 2004 and 2003, the weighted average interest rate for total indebtedness, including our Notes, revolving credit facility, letters of credit, and related miscellaneous fees was 7.7% and 9.6%, respectively.

8. Taxes

Income Taxes

The components of the Company s total income tax expense including amounts related to items shown net of income taxes on the Consolidated Statements of Operations were attributed to the following items (in thousands):

	Year Ended December 31,		
	2004	2003	2002
Taxes related to:			
Income before cumulative effect of accounting change	$ 40,492	$ 36,102	$ 22,616
Cumulative effect of accounting change		529	
Total tax expense	$ 40,492	$ 36,631	$ 22,616

The components of the income tax provision related to income/loss before cumulative effect of accounting change and extraordinary loss are as follows (in thousands):

	Year Ended December 31,		
	2004	2003	2002
Federal:			
Current	$ 1,788	$ 991	$ (745)
Deferred	35,470	32,145	21,552
Total federal	37,258	33,136	20,807

State (net of federal benefit):			
Current	125		
Deferred	3,109	2,966	1,809
Total state	3,234	2,966	1,809
Income tax provision	$ 40,492	$ 36,102	$ 22,616

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ENCORE ACQUISITION COMPANY
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Reconciliation of income tax expense with tax at the Federal statutory rate is as follows (in thousands):

	Year Ended December 31,		
	2004	2003	2002
Income before income taxes	$ 122,639	$ 98,880	$ 60,301
Tax at statutory rate	$ 42,923	$ 34,608	$ 21,105
State income taxes, net of federal benefit	3,234	2,966	1,809
Section 29 & 43 credits	(3,816)	(1,322)	(632)
Change in expected future tax rate	(1,854)		
Perm and other	5	(150)	334
Income tax provision	$ 40,492	$ 36,102	$ 22,616

The major components of the net current deferred tax asset and net long-term deferred tax liability are as follows at December 31 (in thousands):

	December 31,	
	2004	2003
Current:		
Assets:		
Unrealized hedge loss in other comprehensive income	$ 10,550	$ 4,626
Derivative fair loss hedges	568	
Total current deferred tax assets	11,118	4,626
Liabilities:		
Derivative fair value loss		(881)
Other		(153)
Total current deferred tax liabilities		(1,034)
Net current deferred tax asset	$ 11,118	$ 3,592
Long-term:		
Assets:		
Alternative minimum tax	$ 2,017	$ 1,972
Unrealized hedge loss in other comprehensive income	11,522	1,453
Section 43 credits	6,350	1,062
Other	1,504	251
Total long-term deferred tax assets	21,393	4,738

Liabilities:				
Book basis of oil and natural gas properties in excess of tax basis		(167,457)		(85,051)
Net long-term deferred tax liability	$	(146,064)	$	(80,313)

Cash income tax payments in the amount of $3.7 million and $1.5 million were made in 2004 and 2003. No cash income tax payments were made in 2002. If unused, $0.3 million of the Section 43 credits will expire in 2023 and $6.1 million in 2024. Additionally, the Company recognized in equity a benefit resulting from the reduction in income taxes payable related to the exercise of employee stock options in

ENCORE ACQUISITION COMPANY
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

the amount of $1.4 million, $0.1 million, and zero in the years ended December 31, 2004, 2003, and 2002, respectively.

Taxes Other than Income Taxes

Taxes other than income taxes were comprised of the following (in thousands):

	Year Ended December 31,		
	2004	2003	2002
Production and severance	$ 27,491	$ 19,999	$ 14,397
Property and ad valorem	2,822	2,014	1,256
Franchise, payroll and other taxes	868	677	383
Total	$ 31,181	$ 22,690	$ 16,036

9. Stockholders Equity

Public Offerings of Common Stock

On November 13, 2003, the Company priced a public offering of 8.0 million shares of the Company s common stock at a price to the public of $20.25 per share. The underwriters also exercised their over-allotment option for an additional 1.06 million shares of common stock, at a price of $20.25 per share, on December 2, 2003, for a total of 9.06 million shares. The Company used all of the net proceeds to repurchase 6,866,643 shares of the Company s common stock from J.P. Morgan Partners (SBIC), LLC and 2,193,357 shares from Warburg Pincus Equity Partners L.P. at a price of $19.3775 per share. The 9.06 million shares the Company purchased were retired upon repurchase. The Company s total shares outstanding did not change as a result of this offering. Net proceeds from the original offering and the over-allotment option totaled approximately $175.6 million, after deducting underwriting discounts and commissions and the estimated expenses of the offering.

On June 8, 2004, we priced a public offering of 2.0 million shares of our common stock at a price to the public of $26.95 per share. The shares were sold under a shelf registration statement, that had been declared effective by the Securities and Exchange Commission in August 2003. The net proceeds of the offering, after underwriting discounts and commissions, and other related expenses were approximately $52.9 million. The Company used the net proceeds of this offering to repay indebtedness under its revolving credit facility and for general corporate purposes.

Shelf Registration on Form S-3. On June 30, 2004, the Company filed a shelf registration with the SEC on Form S-3 (Registration No. 333-117036). Using this process, we may offer common stock, preferred stock, senior debt and subordinated debt in one or more offerings with a total initial offering price of up to $500 million.

Common Stock Option Exercises

During the years ended December 31, 2004, 2003 and 2002, employees of the Company exercised 202,577, 145,727 and 3,666 options, respectively. The Company received proceeds from the option exercises of $2.8 million, $2.0 million, and $0.1 million in the years ended December 31, 2004, 2003, and 2002, respectively, related to these option exercises.

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ENCORE ACQUISITION COMPANY
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Preferred Stock

The Company s authorized capital stock includes 5,000,000 shares of preferred stock, none of which are issued and outstanding. The Board of Directors has not determined the rights and privileges of holders of such preferred stock, and we have no current plans to issue any shares of preferred stock.

10. Earnings Per Share (EPS)

Under Statement of Financial Accounting Standards No. 128, the Company must report basic EPS, which excludes the effect of potentially dilutive securities, and diluted EPS, which includes the effect of all potentially dilutive securities. EPS for the periods presented is based on weighted average common shares outstanding for the period.

The following table reflects EPS data for the years ended December 31 (in thousands, except per share data):

	Year Ended December 31,		
	2004	2003	2002
Numerator:			
Income before cumulative effect of accounting change	$ 82,147	$ 62,778	$ 37,685
Cumulative effect of accounting change		863	
Net income	$ 82,147	$ 63,641	$ 37,685
Denominator:			
Denominator for basic earnings per share weighted average shares outstanding	31,393	30,102	30,031
Effect of dilutive options and dilutive restricted stock(a)	432	231	130
Denominator for diluted earnings per share	31,825	30,333	30,161
Basic income per common share before accounting change	$ 2.62	$ 2.09	$ 1.25
Cumulative effect of accounting change, net of tax		0.02	
Basic income per common share after accounting change	$ 2.62	$ 2.11	$ 1.25
Diluted income per common share before accounting change	$ 2.58	$ 2.07	$ 1.25
Cumulative effect of accounting change, net of tax		0.03	
Diluted income per common share after accounting change	$ 2.58	$ 2.10	$ 1.25

(a) There were no antidilutive options or antidilutive restricted stock outstanding for the year ended December 31, 2004 and December 31, 2003. Options to purchase 272,177 shares of common stock were outstanding but not included in the above calculation of 2002 diluted earnings per share because their effect would be antidilutive. Additionally, the Company issued 129,328 shares of restricted stock at the end of 2002 which are not included in the calculation of 2002 diluted earnings per share because their effect on the shares outstanding would be nominal.

11. Employee Benefit Plans

401(k) plan

We make contributions to the Encore Acquisition Company 401(k) Plan, which is a voluntary and contributory plan for eligible employees. Our contributions, which are based on a percentage of matching

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ENCORE ACQUISITION COMPANY
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

employee contributions, totaled $0.9 million in 2004, $0.5 million in 2003, and $0.5 million in 2002. The Company s 401(k) plan does not currently allow employees to invest in securities of the Company.

Incentive Stock Plans

During 2000, the Company s Board of Directors and stockholders approved the 2000 Incentive Stock Plan (the Plan). The original plan was amended and restated effective March 18, 2004. The purpose of the Plan is to attract, motivate, and retain selected employees of the Company and to provide the Company with the ability to provide incentives more directly linked to the profitability of the business and increases in shareholder value. All directors and full-time regular employees of the Company and its subsidiaries and affiliates are eligible to be granted awards under the Plan. The total number of shares of common stock reserved for issuance pursuant to the Plan is 3,000,000. As of December 31, 2004, there were 1,361,438 shares remaining under the Plan. The Plan provides for the granting of cash awards, incentive stock options, non-qualified stock options, restricted stock, and stock appreciation rights at the discretion of the Compensation Committee of the Company s Board of Directors.

The Plan contains the following individual limits:

an employee may not be awarded more than 150,000 shares of common stock in any calendar year;

a nonemployee director may not be awarded more than 10,000 shares of common stock in any calendar year; and

an employee may not receive awards consisting of cash (including cash awards that are granted as performance awards) in respect of any calendar year having a value determined on the grant date in excess of $1 million.

The Plan also permits nonqualified stock options at 85% of fair value.

All options that have been granted under the Plan have a strike price equal to the market price on the date of grant. Additionally, all have a ten-year life and vest equally over a two or three-year period. The following table summarizes the changes in the number of outstanding options and their related weighted average strike prices during 2004, 2003, and 2002:

	Year Ended December 31, 2004		Year Ended December 31, 2003		Year Ended December 31, 2002	
	Number of Options	Weighted Average Strike Price	Number of Options	Weighted Average Strike Price	Number of Options	Weighted Average Strike Price
Outstanding at beginning of year	962,954	$ 14.86	1,178,511	$ 14.62	847,500	$ 13.44
Granted(a)	259,856	26.13	49,792	19.45	378,177	17.21
Forfeited	(6,509)	15.74	(119,622)	16.11	(43,500)	14.24
Exercised	(202,577)	13.60	(145,727)	13.43	(3,666)	14.00
Outstanding at end of year	1,013,724	18.00	962,954	14.86	1,178,511	14.62
Exercisable at end of year	632,514	14.66	581,610	13.95	324,278	13.31

(a) During 2004 and 2003, 25,000 and 15,000 of the options, respectively, were granted to non-employee directors. The weighted average fair value of individual options granted in 2004 and 2003 was $10.31 and $6.38, respectively.

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ENCORE ACQUISITION COMPANY
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Additional information about common stock options outstanding and exercisable at December 31, 2004 is as follows:

	Options Outstanding		
Range of Strike Prices per Share	Number of Options	Weighted Average Life (Years)	Weighted Average Strike Price
$12.49 to $14.00	480,148	6.5	$ 13.32
$14.01 to $29.65	533,576	8.5	22.21

During the years ended December 31, 2004, 2003, and 2002, we issued 68,071, 45,461, and 77,901 shares, respectively, of restricted stock to employees which depend only on continued employment for vesting. The following table illustrates by year of grant the vesting of shares which remain outstanding at December 31, 2004:

	Year of Vesting					
Year of Grant	2005	2006	2007	2008	2009	Total
2002	23,775	23,775	23,774			71,324
2003		13,772	13,772	13,772		41,316
2004	19,423	19,423	22,690	3,268	3,267	68,071
Total	43,198	56,970	60,236	17,040	3,267	180,711

During the years ended December 31, 2004, 2003, and 2002, we issued 57,693, zero, and 51,427 shares of restricted stock to employees that not only depend on the passage of time and continued employment, but on certain performance measures, for their vesting. The following table illustrates by year of grant the vesting of shares which remain outstanding at December 31, 2004:

	Year of Vesting					
Year of Grant	2005	2006	2007	2008	2009	Total
2002	11,488	11,488	11,488			34,464
2003						
2004			19,231	19,231	19,231	57,693
Total	11,488	11,488	30,719	19,231	19,231	92,157

Deferred compensation of $3.4 million was reclassified within equity from additional paid in capital during the year ended December 31, 2004 in conjunction with the 2004 grants, and will be expensed over the related periods from the grant dates to the vesting dates.

Subsequent to December 31, 2004, we issued 164,703 shares of restricted stock to our employees as part of our annual incentive program.

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ENCORE ACQUISITION COMPANY
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

12. Financial Instruments

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

	December 31, 2004		December 31, 2003	
	Book Value	Fair Value	Book Value	Fair Value
Cash and cash equivalents	$ 1,103	$ 1,103	$ 431	$ 431
Accounts receivable, net	43,839	43,839	27,640	27,640
Accounts payable	(24,375)	(24,375)	(10,668)	(10,668)
$8^3/8$% Notes	(150,000)	(166,500)	(150,000)	(162,750)
$6^1/4$% Notes	(150,000)	(148,500)		
Revolving credit facility	(79,000)	(79,000)	(29,000)	(29,000)
Commodity derivative contracts	(52,394)	(52,394)	(7,768)	(7,768)
Interest rate swaps	462	462	2,420	2,420
Plugging bond	625	737	589	643

The book value of cash and cash equivalents approximates fair value because of the short maturity of these instruments. The fair values of our Notes were determined using their open market quote as of December 31, 2004. The difference between book value and fair value represents the premium or discount on that date. The book value of the revolving credit facility approximates the fair value as the interest rate is variable. The plugging bond is classified as held to maturity and therefore is recorded at amortized cost, which at December 31, 2004 is less than fair value. Commodity contracts and interest rate swaps are marked-to-market each quarter in accordance with the provisions of SFAS 133.

Commodity Derivatives

The Company hedges commodity price risk with swap contracts, put contracts, and collar contracts and hedges interest rate risk with swap contracts. Swap contracts provide a fixed price for a notional amount of volume. Put contracts provide a fixed floor price on a notional amount of volume while allowing full price participation if the relevant index price closes above the floor price. Collar contracts provide a floor price for a notional amount of volume while allowing some additional price participation if the relevant index price closes above the floor price. Additionally, we occasionally sell put contracts with a strike price well below the floor price of the collar. These short put contracts do not qualify for hedge accounting under SFAS 133, and accordingly, the mark-to-market change in the value of these contracts is recorded as fair value gain/loss in the Consolidated Statement of Operations.

In order to more effectively hedge the cash flows received on our oil and natural gas production, the Company enters into financial instruments, commonly called basis swaps, whereby we swap certain per Bbl or per Mcf floating market indices for a fixed amount. These market indices are a component of the price the Company is paid on its actual production and by fixing this component of our marketing price, we are able to realize a net price with a more consistent differential to NYMEX. Since NYMEX is the basis of all our derivative oil hedging contracts and some of our natural gas contracts, a more consistent differential results in more effective hedges. However, management has elected not to use hedge accounting for certain of these contracts. Instead, we mark these contracts to market each quarter through Derivative fair value (gain) loss in the Consolidated Statements of Operations. Thus, as these contracts do not change the Company s overall hedged volumes, average prices presented in the table below are exclusive of any effect of these non-hedge instruments. As of December 31, 2004, the mark-to-market value of these contracts was $0.4 million.

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ENCORE ACQUISITION COMPANY
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

The following tables summarize our open commodity derivative positions designated as cash flow hedges as of December 31, 2004:

Oil Hedges at December 31, 2004

Period	Daily Floor Volume (Bbls)	Floor Price (per Bbl)	Daily Cap Volume (Bbls)	Cap Price (per Bbl)	Daily Swap Volume (Bbls)	Swap Price (per Bbl)	Fair Market Value (In thousands)
Jan. June 2005	15,500	$ 27.55	3,500	$ 31.89	1,000	$ 25.12	$ (10,340)
July Dec. 2005	12,500	27.84	2,500	31.07	1,000	25.12	(6,810)
Jan. June 2006	3,000	32.50	1,000	29.88	2,000	25.03	(6,296)
July Dec. 2006	1,000	27.50	1,000	29.88	2,000	25.03	(6,928)
Jan. Dec. 2007					2,000	25.11	(9,104)

Natural Gas Hedges at December 31, 2004

Period	Daily Floor Volume (Mcf)	Floor Price (per Mcf)	Daily Cap Volume (Mcf)	Cap Price (per Mcf)	Daily Swap Volume (Mcf)	Swap Price (per Mcf)	Fair Market Value (In thousands)
Jan. Dec. 2005	10,000	$ 4.84	5,000	$ 5.97	12,500	$ 4.99	$ (5,155)
Jan. Dec. 2006	5,000	4.85	5,000	5.68	12,500	5.08	(5,822)
Jan. Dec. 2007					10,000	4.99	(2,309)

As a result of all of our hedging transactions for oil and natural gas, we recognized a pre-tax reduction in revenues of approximately $38.0 million, $15.3 million, and $5.2 million, in 2004, 2003, and 2002, respectively. Based on the fair value of our hedges at December 31, 2004, our unrealized pre-tax loss recorded in other comprehensive income related to outstanding hedges was $45.2 million for oil and $13.7 million for natural gas. Of the total deferred hedge loss at December 31, 2004 related to commodity contracts, $28.1 million, $19.5 million, $11.3 million relate to 2005, 2006, and 2007 contracts, respectively.

Interest Rate Derivatives

As discussed in Note 7. Indebtedness, in conjunction with the sale of the 3/8% Notes, the Company repaid all amounts outstanding under its previous credit facility on June 25, 2002, and terminated the prior revolving credit facility on that date. At the time, the Company had three interest rate swaps outstanding, with a notional amount of $30 million each, which swapped LIBOR based floating rates for fixed rates. According to the provisions of SFAS 133, these no longer qualified for hedge accounting as of June 25, 2002. Their unrealized loss of $3.8 million through June 25, 2002 was recognized in accumulated other comprehensive income, and is being amortized to interest expense over the original life of the swaps as follows (in thousands):

Year	1st Quarter	2nd Quarter	3rd Quarter	4th Quarter	Total

2002	$	$ (59)	$ (806)	$ (754)	$ (1,619)
2003	(654)	(544)	(414)	(297)	(1,909)
2004	(212)	(153)	(109)	(72)	(546)
2005	(40)	72	85	60	177
2006	22	24	29	33	108
2007	38	1			39
Total					$ (3,750)

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ENCORE ACQUISITION COMPANY
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

During the third quarter of 2002, the Company cash settled one of three interest rate swaps discussed above and during the first quarter of 2003, the Company cash settled the remaining two. This resulted in a gain $0.6 million in 2003 and a loss of $0.4 million in 2002, which was included in Derivative fair value (gain) loss in the Consolidated Statements of Operations.

The following table summarizes the Company s only remaining interest rate swap contract at December 31, 2004:

Contract Expiration	Notional Amount	Encore Pays	Encore Receives	Fair Market Value
June 2005	$ 80,000,000	LIBOR + 3.89%	8.375%	$ 462

We recognized in interest expense a pre-tax loss of approximately $0.5 million, $1.9 million, and $1.6 million in 2004, 2003, and 2002, respectively. Additionally, $0.3 million was recognized in Derivative fair value (gain) loss in 2004 for settlements and changes in fair value of our current interest rate swap, which does not qualify for hedge accounting.

The actual gains or losses we realize from our derivative transactions may vary significantly from the deferred loss amount recorded in equity at December 31, 2004 due to the fluctuation of prices in the commodities markets and/or fluctuations in the floating LIBOR interest rate.

Counterparty Risk

The Company s counterparties to hedging contracts include: BNP Paribas; Calyon; Deutsche Bank; Mitsui & Co.; Morgan Stanley; Shell Trading; Wachovia; and J. Aron & Company, a wholly-owned subsidiary of Goldman, Sachs & Co. At December 31, 2004, approximately 34%, 24%, 15%, and 15% of the Company s estimated hedged oil production was committed to Morgan Stanley, Deutsche Bank, J. Aron & Company, and Calyon, respectively. At December 31, 2004, approximately 63%, 16%, 11% and 10% of the Company s hedged gas production was contracted with J. Aron & Company, BNP Paribas, Mitsui & Co., and Morgan Stanley, respectively. Performance on all of the Company s contracts with J. Aron & Company was guaranteed by its parent, Goldman, Sachs & Co. The Company feels the credit-worthiness of the current counterparties is sound and the Company does not anticipate any non-performance of contractual obligations. As long as each counterparty maintains an investment grade credit rating, pursuant to our hedging contracts, no collateral is required.

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

13. Termination of Enron Hedges

On December 2, 2001, Enron Corp. and certain subsidiaries, including Enron North America Corp. (Enron), each filed voluntary petitions for relief under Chapter 11 of Title 11 of the United States Bankruptcy Code. Prior to this date, the Company had entered into oil and natural gas hedging contracts with Enron, many of which were set to expire at December 31, 2001; however, others related to 2002 and 2003. As a result of the Chapter 11 bankruptcy declaration and pursuant to the terms of the Company s contract with Enron, we terminated all outstanding oil and natural gas derivative contracts with Enron as

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ENCORE ACQUISITION COMPANY
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

of December 12, 2001. According to the terms of the contract, Enron is liable to the Company for the mark-to-market value of all contracts outstanding on that date, which totaled $6.6 million. Additionally, Enron failed to make timely payment of $0.4 million in 2001 hedge settlements. Both of these amounts remained outstanding as of December 31, 2001. Due to the uncertainty of future collection of any or all of the amounts owed to the Company by Enron, the Company recorded an allowance for the full amount of the receivable of $7.0 million.

At the time of termination, the market price of our commodity contracts with Enron exceeded their amortized cost on our balance sheet, giving rise to a gain. In accordance with the provisions of SFAS 133, this gain was recorded in other comprehensive income and was reversed into earnings during 2003 and 2002. The following table illustrates the amortization of this amount to revenue by year (in thousands):

Period	Oil Revenue	Natural Gas Revenue	Total
2002	$ 2,822	$ 1,594	$ 4,416
2003	401	18	419
Total	$ 3,223	$ 1,612	$ 4,835

During the first quarter of 2003, due to continued uncertainty of any ultimate collection and continuing legal fees, the Company sold its entire Enron receivable to a third party for $0.5 million. As the receivable was fully reserved, this amount was recorded as a gain in 2003 and included in Other operating expense in the Consolidated Statements of Operations.

With the Cortez acquisition (see Note 3. Acquisitions), the Company acquired an Enron derivative contract. To negate any adverse effects of this contract, the Company entered into another contract with opposite terms.

The Company actively evaluates the credit exposure related to its derivatives and receivables, and considers its history with the debtor, how long the amount has been outstanding, potential offsets to the amount owed, and general economic conditions. Other than the Enron receivable, the Company is not aware of any conditions which warrant an allowance or write-off of a receivable or derivative position.

14. Related Party Transactions

The Company paid $0.3 million to Hanover Compression Company in 2004 for compression services. Mr. I. Jon Brumley, the Company s Chairman, Director, and CEO, also serves as a director of Hanover Compressor Company.

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

The capitalized cost of oil and natural gas properties at December 31, 2004 and 2003 are as follows (in thousands):

	December 31,	
	2004	2003
Properties and equipment, at cost successful efforts method:		
Proved properties	$ 1,134,220	$ 739,288
Unproved properties	29,740	921
Accumulated depletion, depreciation, and amortization	(171,691)	(124,646)
	$ 992,269	$ 615,563

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ENCORE ACQUISITION COMPANY
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

The following table summarizes costs incurred related to oil and natural gas properties:

	Year Ended December 31,		
	2004	2003	2002
		(In thousands)	
Acquisitions			
Proved properties	$ 204,907	$ 54,484	$ 78,158
Unproved properties	33,926	117	391
Asset retirement obligations(1)	1,165	337	
Total acquisitions	239,998	54,938	78,549
Development			
Drilling and exploitation	157,092	98,977	80,313
Asset retirement obligations(1)	467	83	
Total development	157,559	99,060	80,313
Exploration			
Drilling and exploitation	29,363		
Geological and seismic	979		
Delay rentals	204		
Total exploration	30,546		
Total costs incurred	$ 428,103	$ 153,998	$ 158,862

(1) The Company adopted SFAS 143 on January 1, 2003 which requires us to capitalize additional asset cost equal to the amount of our discounted asset retirement obligation assumed in a property purchase or incurred in the drilling of new wells. Had the Company adopted SFAS 143 prior to January 1, 2002, the Company s acquisition cost incurred on a pro-forma basis would have been increased by $0.7 million for the year ended December 31, 2002. The effect on the Company s development cost incurred on a pro-forma basis would have been insignificant.

SUPPLEMENTAL INFORMATION (unaudited)

16. Oil & Natural Gas Producing Activities (unaudited)

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

Future prices received for production and future production costs may vary, perhaps significantly, from the prices and costs assumed for purposes of these estimates. There can be no assurance that the proved reserves will be developed within the periods assumed or that prices and costs will remain constant. Actual production may not equal the estimated amounts used in the preparation of reserve projections. In accordance with Securities and Exchange Commission s guidelines, the Company s estimates of future net cash flows from the properties and the representative value thereof are made using oil and natural gas prices in effect as of the dates of such estimates and are held constant throughout the life of the properties. Average prices used in estimating net cash flows at December 31, 2004, 2003, and 2002 were $43.46, $32.55, and $31.20 per barrel, respectively, for oil and $6.19, $5.83, and $4.79 per Mcf, respectively, for natural gas. The net profits interest on our Cedar Creek Anticline properties has been

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ENCORE ACQUISITION COMPANY
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

There are numerous uncertainties inherent in estimating quantities of proved reserves and in projecting future rates of production and timing of development expenditures. Oil and natural gas reserve engineering is and must be recognized as a subjective process of estimating underground accumulations of oil and natural gas that cannot be measured in any exact way, and estimates of other engineers might differ materially from those included in this Annual Report on Form 10-K. The accuracy of any reserve estimate is a function of the quality of available data and engineering, and estimates may justify revisions. Accordingly, reserve estimates are often materially different from the quantities of oil and natural gas that are ultimately recovered. Reserve estimates are integral to management s analysis of impairments of oil and natural gas properties and the calculation of depletion, depreciation, and amortization on these properties.

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

	Oil (MBbl)	Natural Gas (MMcf)	Oil Equivalent (MBOE)
December 31, 2004			
Proved reserves	134,048	234,030	173,053
Proved developed reserves	97,114	156,919	123,267
December 31, 2003			
Proved reserves	117,732	138,950	140,890
Proved developed reserves	92,377	104,767	109,838
December 31, 2002			
Proved reserves	111,674	99,818	128,310
Proved developed reserves	93,945	82,217	107,648

Encore is committed to sell at least 2,500 barrels of oil per day at a floating market price through 2009.

ENCORE ACQUISITION COMPANY
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

The change in proved reserves were as follows for the years ended:

	Oil (MBbl)	Natural Gas (MMcf)	Oil Equivalent (MBOE)
Balance, December 31, 2001	91,369	75,687	103,983
Acquisitions of minerals-in-place	14,555	5,434	15,461
Extensions and discoveries	9,605	23,643	13,546
Revisions of estimates	2,182	3,229	2,719
Production	(6,037)	(8,175)	(7,399)
Balance, December 31, 2002	111,674	99,818	128,310
Acquisitions of minerals-in-place	13	37,464	6,257
Extensions and discoveries	3,957	7,354	5,182
Improved recovery	12,773	(178)	12,744
Revisions of estimates	(4,084)	3,543	(3,493)
Production	(6,601)	(9,051)	(8,110)
Balance, December 31, 2003	117,732	138,950	140,890
Acquisitions of minerals-in-place	7,853	86,314	22,239
Extensions and discoveries	4,226	27,248	8,768
Improved recovery	11,826	(80)	11,812
Revisions of estimates	(910)	(4,313)	(1,629)
Production	(6,679)	(14,089)	(9,027)
Balance, December 31, 2004	134,048	234,030	173,053

The Standardized Measure of discounted estimated future net cash flows and changes therein related to proved oil and natural gas reserves (in thousands) is as follows as of the dates indicated:

	December 31,		
	2004	2003	2002
Net future cash inflows	$ 6,651,858	$ 4,245,574	$ 3,648,515
Future production costs	(2,389,359)	(1,683,810)	(1,448,110)
Future development costs	(194,746)	(75,811)	(63,194)
Future abandonment costs	(49,859)	(43,641)	
Future income tax expense	(1,221,933)	(716,869)	(623,987)
Future net cash flows	2,795,961	1,725,443	1,513,224
10% annual discount	(1,630,342)	(988,504)	(888,506)

Standardized measure of discounted estimated future net cash flows	$	1,165,619	$	736,939	$	624,718

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ENCORE ACQUISITION COMPANY
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Primary changes in the Standardized Measure of discounted estimated future net cash flows (in thousands) are as follows for the periods indicated:

	Year Ended December 31,		
	2004	2003	2002
Standardized measure, beginning of year	$ 736,939	$ 624,718	$ 284,309
Net change in sales prices and production costs	430,310	81,964	305,097
Acquisitions of minerals-in-place	242,855	91,654	131,370
Extensions, discoveries, and improved recovery	150,112	103,780	135,897
Revisions of quantity estimates	(15,217)	(25,650)	18,216
Sales, net of production costs	(222,995)	(151,955)	(114,361)
Development costs incurred during the year	157,092	98,977	80,313
Accretion of discount	73,694	86,511	36,036
Change in estimated future development costs	(276,027)	(116,859)	(44,285)
Net change in income taxes	(145,042)	(52,992)	(164,334)
Change in timing and other	33,898	(3,209)	(43,540)
Standardized measure, end of year	$ 1,165,619	$ 736,939	$ 624,718

ENCORE ACQUISITION COMPANY
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

17. Selected Quarterly Financial Data (unaudited)

The following table sets forth selected quarterly financial data for the years ended December 31, 2004 and 2003:

	Quarter			
	First	Second	Third	Fourth
	(In thousands, except per share data)			
2004				
Revenues	$ 59,291	$ 70,122	$ 79,252	$ 89,868
Operating Income	30,249	34,201	38,010	43,398
Net income	16,902	17,991	21,014	26,240
Basic income per common share	0.56	0.59	0.65	0.81
Diluted income per common share	0.55	0.58	0.64	0.80
2003				
Revenues	$ 55,787	$ 51,243	$ 55,724	$ 57,342
Operating Income	31,377	26,679	28,789	27,972
Income before accounting change	17,115	14,233	15,768	15,662
Cumulative effect of accounting change, net of tax of $529	863			
Net income	$ 17,978	$ 14,233	$ 15,768	$ 15,662
Basic income per common share:				
Before accounting change	$ 0.57	$ 0.47	$ 0.52	$ 0.51
Accounting change, net of tax	0.03			
After accounting change	$ 0.60	$ 0.47	$ 0.52	$ 0.51
Diluted income per common share:				
Before accounting change	$ 0.57	$ 0.47	$ 0.52	$ 0.51
Accounting change, net of tax	0.02			
After accounting change	$ 0.59	$ 0.47	$ 0.52	$ 0.51

Item 9. ***Changes in and Disagreements with Accountants on Accounting and Financial Disclosure***

None.

Item 9A. ***Controls and Procedures***

Evaluation of Disclosure Controls and Procedures

As of the end of the period covered by this report, we carried out an evaluation, under the supervision and with the participation of our management, including our Chief Executive Officer and Chief Financial Officer, of the effectiveness of the design and operation of our disclosure controls and procedures (as defined in Rule 13a-15(e) of the Securities Exchange Act of 1934, as amended (the Exchange Act)). Based upon that evaluation, the Chief Executive Officer and the Chief Financial Officer concluded that, as of December 31, 2004, our disclosure controls and procedures were effective to provide reasonable assurance that information required to be disclosed by the Company in the reports that it files or submits under the Exchange Act is recorded, processed, summarized, and reported within the time periods specified in applicable rules and forms.

Management s Report on Internal Control Over Financial Reporting

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

As of December 31, 2004, management assessed the effectiveness of the Company s internal control over financial reporting based on the criteria for effective internal control over financial reporting established in Internal Control Integrated Framework, issued by the Committee of Sponsoring Organizations of the Treadway Commission. Based on that assessment, management determined that the Company maintained effective internal control over financial reporting as of December 31, 2004, based on those criteria.

Ernst & Young, LLP, the independent registered public accounting firm that audited the consolidated financial statements of the Company included in this Annual report on Form 10-K, has issued an attestation report on management s assessment of the effectiveness of the Company s internal control over financial reporting as of December 31, 2004. The report, which expresses unqualified opinions on management s assessment and on the effectiveness of the Company s internal control over financial reporting as of December 31, 2004, is included in this Annual Report on Form 10-K, Item 9A. under the heading Report of Independent Registered Public Accounting Firm on Internal Control Over Financial Reporting.

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

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

We have audited management s assessment, included in the accompanying Management s Report on Internal Control over Financial Reporting appearing under Item 9A, that Encore Acquisition Company and subsidiaries (the Company) maintained effective internal control over financial reporting as of December 31, 2004, based on the criteria established in *Internal Control Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). Management of the Company is responsible for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting. Our responsibility is to express an opinion on management s assessment and an opinion on the effectiveness of the internal control over financial reporting of the Company based on our audit.

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

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

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

In our opinion, management s assessment that the Company maintained effective internal control over financial reporting as of December 31, 2004, is fairly stated, in all material respects, based on criteria established in *Internal Control Integrated Framework* issued by the COSO. Also, in our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2004, based on the criteria established in *Internal Control Integrated Framework* issued by COSO.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the consolidated balance sheets of the Company as of December 31, 2004 and 2003, and the related consolidated statements of operations, stockholders equity, and cash flows for each of the years in the three-year period ended December 31, 2004, and our report dated March 7, 2005 expressed an unqualified opinion on thereon.

/s/ Ernst & Young LLP

Fort Worth, Texas
March 7, 2005

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Changes in Internal Control over Financial Reporting

There were no changes in our internal control over financial reporting that occurred during the most recent fiscal quarter that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

Item 9B. *Other Information*

None.

PART III

Item 10. *Directors and Executive Officers of the Registrant*

The information required in response to this item is set forth under the captions Corporate Governance Principles and Board Matters Governance Framework, Corporate Governance Principles and Board Matters Board Structure and Composition, Proposals to be Voted On Proposal No. 1 Election of Directors, Executive Officers and Section 16(a) Beneficial Ownership Reporting Compliance in the Company s definitive proxy statement for the 2005 annual meeting of stockholders and is incorporated herein by reference.

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

Item 11. *Executive Compensation*

The information required in response to this item is set forth under the captions Corporate Governance Principles and Board Matters Compensation of Directors and Executive Compensation (other than the information under the caption Compensation Committee Report On Executive Compensation) in the Company s definitive proxy statement for the 2005 annual meeting of stockholders and is incorporated herein by reference.

Item 12. *Security Ownership of Certain Beneficial Owners and Management and Related Stockholder Matters*

The information required in response to this item is set forth under the caption Security Ownership of Certain Beneficial Owners and Management in the Company s definitive proxy statement for the 2005 annual meeting of stockholders and is incorporated herein by reference.

The following table sets forth information about the Company s common stock that may be issued under the Company s equity compensation plans as of December 31, 2004:

	(a)	(b)	(c)
	Number of Securities to Be Issued upon Exercise of Outstanding Options, Warrants and Rights (2)	Weighted-Average Exercise Price of Outstanding Options, Warrants and Rights	Number of Securities Remaining Available for Future Issuance Under Equity Compensation Plans (Excluding Securities Reflected in Column (a))
	1,013,724	$ 18.00	1,361,438

Equity compensation plans approved by security holders(1)			
Equity compensation plans not approved by security holders			
Total	1,013,724	$ 18.00	1,361,438

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

(2) Excludes 272,922 shares of restricted stock.

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Item 13. ***Certain Relationships and Related Transactions***

The information required in response to this item is set forth under the caption Certain Relationships and Related Transactions in the Company s definitive proxy statement for the 2005 annual meeting of stockholders and is incorporated herein by reference.

Item 14. ***Principal Accountant Fees and Services***

The information required in response to this item is set forth under the caption Principal Accountant Fees and Services in the Company s definitive proxy statement for the 2005 annual meeting of stockholders and is incorporated herein by reference.

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PART IV

Item 15. ***Exhibits and Financial Statement Schedules***

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

1. *Financial Statements:*

2. *Financial Statement Schedules:*

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

(b) *Exhibits*

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

INDEX TO EXHIBITS

Exhibit No.	Description
3.1	Second Amended and Restated Certificate of Incorporation of the Company (incorporated by reference to the Company s Quarterly Report on Form 10-Q for the fiscal quarter ended September 30, 2001, filed with the SEC on November 7, 2001).
3.2	Second Amended and Restated Bylaws of the Company (incorporated by reference to the Company s Quarterly Report on Form 10-Q for the fiscal quarter ended September 30, 2001, filed with the SEC on November 7, 2001).
4.1	Specimen certificate of the Company (incorporated by referenced to Exhibit 4.1 to Registration Statement on Form S-1, Registration No. 333-47540, filed with the SEC on December 15, 2000).
4.2	Indenture, dated as of June 25, 2002, among the Company, subsidiary guarantors party thereto and Wells Fargo Bank, N.A. (incorporated by reference to Exhibit 4.1 to Quarterly Report on Form 10-Q for the quarterly period ended June 30, 2002, filed with the SEC on August 9, 2002).
4.3	Form of $8^{3}/8$% Senior Subordinated Note to Cede & Co. or its registered assigns (included Exhibit A to Exhibit 4.2 above).
4.4	Indenture, dated as of April 2, 2004, among the Company, the subsidiary guarantors party thereto and Wells Fargo Bank, National Association (incorporated by reference to Exhibit 4.1 of the Company s Registration Statement on Form S-4 (Registration No. 333-117025), filed with the SEC on June 30, 2004).
4.5	Form of 6.25% Senior Subordinated Note to Cede & Co. or its registered assigns (included Exhibit A to Exhibit 4.4 above).
10.1+	2000 Incentive Stock Plan (incorporated by reference to Exhibit 4.1 to the Company s Registration Statement on Form S-8 (File No. 333-120422), filed with the SEC on November 12, 2004).
10.2+	Employee Severance Protection Plan (incorporated by reference to Exhibit 10.1 to the Company s Quarterly Report on Form 10-Q for the quarterly period ended March 31, 2003, filed with the SEC on May 8, 2003).
10.3+*	Form of Restricted Stock Award Executive
10.4+*	Form of Stock Option Agreement (Nonqualified)
10.5+*	Form of Stock Option Agreement (Incentive)
10.6*	Form of Indemnification Agreement for directors and executive officers
10.7*+	Table of 2005 Base Salaries for Executive Officers of the Company
10.8	Description of Compensation Payable to Non-Management Directors (incorporated by reference to Exhibit 10.1 of the Company s Form 8-K, filed with the SEC on February 18, 2005).
10.9	Amended and Restated Credit Agreement, dated August 19, 2004, among the Company, Encore Operating, L.P., Bank of America, N.A., as Administrative Agent, Fotis Capital Corp. and Wachovia Bank, N.A., as Co-Syndication Agents, BNP Paribas and Citibank, N.A., as Co-Documentary Agents and the financial institutions party thereto (incorporated by reference to Exhibit 10.1 to the Company s Current Report on Form 8-K, filed with the SEC on August 25, 2004).
10.10	Registration Rights Agreement, dated August 18, 1998, by and among the Company and the other parties thereto (incorporated by reference to Exhibit 4.2 to the Company s Registration Statement on Form S-1 (File No. 333-47540), filed with the SEC on October 6, 2000).
10.11	Stock Purchase Agreement dated March 2, 2004 by and among Cortez Oil & Gas, Inc., HRM Resources, Inc., the Security Holders of Cortez Oil & Gas, Inc., and the Company (incorporated by reference to Exhibit 10.9 of the Company s 2003 Annual Report on Form 10-K for the year ended December 31, 2003).

10.12	Purchase and Sale Agreement, dated as of April 26, 2004, among Dale Resources, L.L.C. et. al. and Encore Operating, L.P. (incorporated by reference to Exhibit 2.1 of the Company s Form 8-K, filed with the SEC on June 23, 2004).

Exhibit No.	Description
10.13	Purchase and Sale Agreement, dated as of April 26, 2004, between Overton Pipeline Company L.P. and EAP Energy Services, L.P. (incorporated by reference to Exhibit 2.2 of the Company s Form 8-K, filed with the SEC on June 23, 2004).
21.1*	Subsidiaries of the Company.
23.1*	Consent of Ernst & Young LLP
23.2*	Consent of Miller and Lents, Ltd.
24.1*	Power of Attorney (included on the signature page of this report).
31.1*	Rule 13a-14(a)/15d-14(a) Certification (Principal Executive Officer)
31.2*	Rule 13a-14(a)/15d-14(a) Certification (Principal Financial Officer)
32.1*	Section 1350 Certification (Principal Executive Officer)
32.2*	Section 1350 Certification (Principal Financial Officer)

* Filed herewith

\+ Management contract or compensatory plan, contract or arrangement

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SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized, on the 9th day of March, 2005.

Encore Acquisition Company
By /s/ I. Jon Brumley

I. Jon Brumley
Chief Executive Officer

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

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the registrant in the capacities indicated on March 9, 2005.

Signature	Title or Capacity
/s/ I. Jon Brumley I. Jon Brumley	Chairman of the Board, Chief Executive Officer, and Director (Principal Executive Officer)
/s/ Jon S. Brumley Jon S. Brumley	President and Director
/s/ Roy W. Jageman Roy W. Jageman	Chief Financial Officer, Treasurer, Executive Vice President and Corporate Secretary (Principal Financial Officer)
/s/ Robert C. Reeves Robert C. Reeves	Vice President, Controller and Assistant Corporate Secretary (Principal Accounting Officer)
/s/ Martin C. Bowen Martin C. Bowen	Director
/s/ Ted Collins, Jr. Ted Collins, Jr.	Director

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Signature	Title or Capacity
/s/ Ted A. Gardner	Director
Ted A. Gardner	
/s/ John V. Genova	Director
John V. Genova	
/s/ Howard H. Newman	Director
Howard H. Newman	
/s/ James A. Winne III	Director
James A. Winne III	

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