ENCORE ACQUISITION CO
Form 10-K
March 24, 2003

UNITED STATES SECURITIES AND EXCHANGE COMMISSION
WASHINGTON, D.C. 20549

FORM 10-K

(Mark One)
[X] ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934

FOR THE FISCAL YEAR ENDED DECEMBER 31, 2002

Commission File No. 1-16295

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

DELAWARE (State or other jurisdiction of incorporation or organization)	75-2759650 (I.R.S. Employer Identification Number)
777 MAIN STREET SUITE 1400 FT. WORTH, TEXAS (Address of principal executive offices)	76102 (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 [X] No [ ]

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. [ ]

Indicate by check mark whether the registrant is an accelerated filer (as defined in Exchange Act Rule 12b-2) Yes [X] No [ ]

Aggregate market value of the voting and non-voting common stock held by non-affiliates of the Registrant as of June 28, 2002 (the last business day of Registrant's most recently completed second fiscal quarter).................	$518,080,000
Number of shares of Common Stock, $0.01 par value, outstanding as of March 20, 2003..........................	30,107,883

DOCUMENTS INCORPORATED BY REFERENCE

Parts of the definitive proxy statement for the Company's annual meeting of stockholders to be held on April 30, 2003 are incorporated by reference into Part III of this report on Form 10-K.

ENCORE ACQUISITION COMPANY
2002 ANNUAL REPORT ON FORM 10-K
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Parts I and II of this annual report on Form 10-K (the "Report") contain forward-looking statements that involve risks and uncertainties that are made pursuant to the Safe Harbor Provisions of the Private Securities Litigation Reform Act of 1995. See "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations" 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 32, 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.

PART I

ITEMS 1 AND 2. BUSINESS AND PROPERTIES

GENERAL

Organized as a Delaware corporation in 1998, Encore Acquisition Company (together with our subsidiaries, "we", "Encore", or the "Company") is a growing independent energy company engaged in the acquisition, development, exploitation, and production of onshore North American oil and natural gas reserves.

Since inception, the Company has sought to acquire high quality assets with potential for upside through low-risk development drilling projects. Our growth has come primarily from the acquisition of producing oil and natural gas properties and subsequent development of these properties. We have been successful in purchasing seven major packages of producing properties since inception in April 1998. The Company has acquired producing properties in the Williston, Permian, Anadarko, Powder River, and Paradox Basins. All our producing assets reside onshore in the continental lower 48 United States. See "-- Properties" beginning on page 12. Since our inception, we have invested $379.3 million in acquiring producing oil and natural gas properties. We have invested another $202.9 million for development and exploitation of these properties.

The Cedar Creek Anticline ("CCA"), in the Williston Basin of Montana and North Dakota, represents 75% of our total proved reserves as of December 31, 2002. The CCA represents the Company's most valuable asset today and in the foreseeable future. A large portion of the Company's future success revolves around future exploitation of and production from this property.

In 2002, our reserve growth was achieved both through acquisitions and organically through the drill bit by developing a portion of the Company's inventory of drilling projects that extends over the next several years. We continued the pursuit of assembling high-quality assets and replenishing our drilling inventory through acquisitions by adding the Central Permian and Paradox Basin properties to the Company's portfolio.

On January 4, 2002, we closed our sixth major property package since inception. These properties were purchased from Conoco for approximately $50.1 million. During the second quarter of 2002, we closed a second, follow-on acquisition of additional working interest for $8.3 million. The Central Permian properties increased our operational presence in West Texas. These properties are located in the Permian Basin near Midland, Texas, and include two major operated fields: East Cowden Grayburg Unit and Fuhrman-Nix; and two non-operated fields: North Cowden and Yates. The properties are 94% oil and the average daily production from the properties for 2002 was 1,978 BOE. The properties have growth potential through development drilling and waterflood enhancement. During 2002, we drilled 8 wells on our Central Permian properties and plan to drill additional wells during 2003.

On August 29, 2002, we completed an acquisition of interests in southeast Utah's Paradox Basin for $17.9 million ($16.7 million after closing adjustments). The Paradox Basin properties are in two prolific oil producing units: the Ratherford Unit operated by Exxon Mobil and the Aneth Unit operated by Chevron Texaco. Since being acquired in 2002, the revenue stream for the properties was derived 92% from oil and

the average daily production added from these properties was 871 BOE. Encore expects to benefit from horizontal redevelopment and tertiary upside opportunities in the future.

In 2002, we drilled 103 gross operated wells and participated in drilling another 6 gross non-operated wells for a total of 109 gross wells for the year. On a net basis, the Company drilled 95 net operated wells and participated in 1 non-operated well in 2002. We invested $80.3 million to drill and complete the net wells for 2002 or approximately $842,000 net per well. The drilling program added 13.5 million BOE for 2002 at an average cost of $5.93 per BOE.

The Company's estimated proved reserves at December 31, 2002 were 111.7 MMBls of oil and 99.8 Bcf of natural gas, or 128.3 MMBOE. The proved developed reserves were 107.6 million BOE, or 84% of total proved reserves at December 31, 2002. Our Reserve-to-Production ratio averaged 17.3 years based upon December 31, 2002 proved reserves and the prior 12 months production, while the R/P Index for our proved reserves at December 31, 2002 for our Cedar Creek Anticline properties was 21.4 years. Prevailing prices as of December 31, 2002 were $31.20 per Bbl of oil and $4.79 per Mcf of natural gas. Proved oil and natural gas reserve quantities are based on estimates prepared by Miller and Lents, Ltd., who are independent petroleum engineers.

Production from our properties averaged 16,540 Bbls/D of oil and 22,397 Mcf/D of natural gas, or 20,273 BOE/D, for 2002. The direct lifting costs for our properties averaged $4.15 per BOE for the year. Production, severance, and ad valorem taxes were $2.12 per BOE.

On June 25, 2002, the Company sold $150 million of 8 3/8% senior subordinated notes maturing on June 15, 2012 (the "Notes") in a private offering exempt from registration requirements under the Securities Act of 1933, as amended. The offering was made through a private placement pursuant to Rule 144A. The Company received net proceeds of $145.6 million from the sale of the Notes, after deducting debt issuance costs. The proceeds were used to repay and retire the Company's prior credit facility ($143.0 million), to pay the fees and expenses related to the new revolving credit facility ($1.5 million), and to hold in reserve for the Paradox Basin acquisition ($1.1 million).

In connection with the issuance of the Notes, we entered into a registration rights agreement, dated June 19, 2002, with the initial purchasers of the Notes and entered into an indenture governing the Notes. Pursuant to the registration rights agreement, we filed a registration statement on Form S-4/A with the SEC, which was declared effective on December 6, 2002, with respect to the exchange of the Notes for registered notes having terms substantially identical in all material respects. On January 16, 2003, all of the Notes were exchanged for the registered notes, Encore's registered senior subordinated notes due June 15, 2012 were issued and the Notes were cancelled. The Company did not receive any proceeds from the exchange. See "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations -- Liquidity and Capital Resources" on page 29.

Concurrently with the issuance of the Notes, we entered into a new revolving credit facility with a syndicate of banks, which replaced our prior credit facility. All of our subsidiaries are guarantors of our revolving credit facility. The maximum amount available under our revolving credit facility is $300.0 million, which is secured by a first priority lien on our proved oil and natural gas reserves representing at least 80% of the present discounted reserve value. As of December 31, 2002, the amount available to us under our revolving credit facility is $220.0 million, the amount of which may be increased and decreased subject to a borrowing base calculation. As of December 31, 2002, $16.0 million was outstanding under the new revolving credit facility. The maturity date is June 25, 2006. See "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations -- Liquidity and Capital Resources" on page 29.

STRATEGY

Our strategy is to grow our reserves and production through low-risk development drilling, selective acquisitions, secondary recovery projects and tertiary recovery projects. This strategy, along with efficient operations, should maximize internally generated cash flow and shareholder value.

Thus, our strategy centers around four primary areas:

- an active low-risk development drilling program;

- a disciplined acquisition program;

- secondary and tertiary recovery projects; and

- cost control through efficient operations.

Development of Existing Properties. Our properties generally have long reserve lives and reasonably stable and predictable reservoir production characteristics. The R/P Index for our proved reserves at December 31, 2002 was 17.3 years based on the prior 12 months' production. However, the R/P Index for our proved reserves at December 31, 2002 for our Cedar Creek Anticline properties, which represented 75% of our total proved reserves, was 21.4 years based on the prior 12 months' production at December 31, 2002. Our Cedar Creek Anticline 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 requires a longer time to produce the reserves in place. This results in a lower production decline rate.

The inventory of potential development drilling locations or major recompletion opportunities on our existing properties is sufficient to sustain the same level of capital investment for the next several years. Longer term, we believe that there is significant value to be created through our High-Pressure Air Injection project in the CCA. See "-- Present Activities -- Cedar Creek Anticline High-Pressure Air Injection Limited Scale Program" on page 9.

Continued Disciplined Acquisition Program. We will continue to pursue acquisitions of properties with similar upside potential to our current producing properties portfolio. We believe that we are more likely to make large property acquisitions during periods of low acquisition prices and will more vigorously pursue development activities during periods of high acquisition prices. The Company, using the experience of our senior management team, has developed and refined an acquisition program designed to increase our reserves and to complement our core properties, while providing some upside potential. We have a staff of engineering and geoscience professionals who manage our core properties and use their experience and expertise to target 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.

Secondary and Tertiary Recovery Projects. Secondary and tertiary recovery is another component of our growth strategy. 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. Our secondary recovery projects involve the successful implementation and further enhancements of waterfloods on the Company's producing properties. The Company also has a tertiary recovery project which revolves around an initial High-Pressure Air Injection ("HPAI") program on the Company's CCA asset in Montana. See "-- Present Activities -- Cedar Creek Anticline High Pressure Air Injection Limited Scale Program" on page 9. These secondary and tertiary projects are expected to yield inclining production rates.

Efficient Operations. We operate properties representing 86% of our proved reserves, which allows us to control capital allocation and expenses. For the year ended December 31, 2002, our lease operating expenses consisted of direct lifting costs of $4.15 per BOE produced and production, ad valorem, and severance tax payments of $2.12 per BOE produced. Our general and administrative costs averaged $0.83 per BOE produced in 2002.

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 returns on investments in a volatile commodity pricing environment, while replenishing our drilling inventory. Changing commodity prices affect the rate of return on a property acquisition, 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.

BUSINESS ACTIVITIES

The following table sets forth the net production, proved reserves quantities, and PV-10 values of our principal properties as of December 31, 2002:

PROPERTIES -- PRINCIPAL AREAS OF OPERATIONS

	NET PRODUCTION FOR THE YEAR 2002				PROVED RESERVE QUANTITIES AT DECEMBER 31, 2002		
	OIL (MBBLS)	NATURAL GAS (MMCF)	TOTAL (MBOE)	PERCENT	OIL (MBBLS)	NATURAL GAS (MMCF)	TOTAL (MBOE)
Cedar Creek Anticline..........	4,316	1,160	4,509	61%	93,118	19,375	96,347

Crockett County......	22	3,768	650	9	101	55,953	9,427
Lodgepole...........	750	401	817	11	2,104	1,104	2,287
Central Permian......	681	242	721	10	10,713	3,280	11,260
Other(2)............	268	2,604	702	9	5,638	20,106	8,989
Total.............	6,037	8,175	7,399	100%	111,674	99,818	128,310

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(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 based on prices current at such dates, our PV-10 value would have been decreased by $4.5 million at December 31, 2002. The Standardized Measure at December 31, 2002 is $624.7 million. Standardized Measure differs from PV-10 because Standardized Measure includes the effect of future income taxes.

(2) Other includes our Indian Basin, Verden, Bell Creek, and Paradox Basin properties, which individually represent less than 10% of our net production for 2002 and PV-10 at December 31, 2002. Additionally, this line includes a reduction to PV-10 at December 31, 2002, of $8.9 million related to future corporate indirect costs.

During 2003, we plan to invest approximately $105.0 million to exploit and develop existing core properties. The $105.0 million budgeted does not include the possible $25.0 million for additional high-pressure air-injection capital. See "-- Present Activities -- Cedar Creek Anticline High-Pressure Air Injection Limited Scale Program" on page 9. With the $105.0 million budgeted capital, we plan to support a 5 rig, 100 well drilling program in the Cedar Creek Anticline and a 2 rig, 40 well program in our Permian Basin assets, as well as waterflood improvements, workovers, and recompletions. If attractive opportunities arise during that period, we will seek to acquire additional producing oil and natural gas properties.

OPERATIONS

We act as operator of properties representing approximately 86% of our proved reserves at December 31, 2002. As operator, we are able to control expenses, capital allocation, and the timing of exploitation and development activities of these properties. Our remaining properties are operated by third parties, and, as working interest owners in those properties, we are required to pay our share of the costs of exploiting and developing them. See "-- Properties -- Nature of Our Ownership Interests" on page 12. During the years ended December 31, 2002, 2001, and 2000 our approximate costs for development activities on non-operated properties were $3.4 million, $9.3 million, and $0.3 million, respectively.

PROVED RESERVES

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):

	HISTORICAL		
	DECEMBER 31, 2002	DECEMBER 31, 2001	DECEMBER 31, 2000
Oil (Bbls)			
Developed	93,945	71,639	66,363
Undeveloped	17,729	19,730	12,547
Total	111,674	91,369	78,910
Natural Gas (Mcf)			
Developed	82,217	69,941	66,337
Undeveloped	17,601	5,746	6,633
Total	99,818	75,687	72,970
Total (BOE)(1)	128,310	103,983	91,072
PV-10(2)			
Developed	$732,823	$299,383	$630,429
Undeveloped	132,281	60,979	75,928
Total	$865,104	$360,362	$706,357
Standardized Measure(3)	$624,718	$284,309	$599,276
Reserve price assumptions			
Oil ($/Bbl)	$ 31.20	$ 19.84	$ 26.80
Natural gas ($/Mcf)	4.79	2.57	9.77

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(1) Volumetric reserves attributed to the net profits interests in our Cedar Creek Anticline properties were 16,262 MBOE, 11,062 MBOE and 11,730 MBOE, respectively, at December 31, 2002, 2001 and 2000. See "-- Net Profits Interests" on page 12. The volumes attributed to the net profits interests, which reduce our reserves on a BOE for BOE basis, will fluctuate from period to period 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 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 based on prices current at such dates, our PV-10 value would have been $860.6 million at December 31, 2002, $364.4 million at December 31, 2001, and $689.6 million at December 31, 2000.

(3) 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 future income taxes.

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.

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 the SEC, 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, expenses exclude our share of overhead charges. In addition, the calculation of estimated future costs does not take into account the effect of various cash outlays, including, among other things, general and administrative costs and interest expense.

During calendar year 2002, the Company filed estimates of oil and natural gas reserves at December 31, 2001 with the U.S. Department of Energy on Form EIA-23. As required for the EIA-23, this filing reflects only production that comes from Company operated wells at year end, and is reported on a gross basis. These estimates come directly from the Company's reserve report that is 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 and certain price and cost information for each of the periods indicated:

	YEAR ENDED DECEMBER 31,		
	2002	2001	2000
PRODUCTION DATA:			
Oil (MBbls)	6,037	4,935	3,961
Natural gas (MMcf)	8,175	8,078	4,303
Combined volumes (MBOE)	7,399	6,281	4,678

AVERAGE PRICES:			
Oil (per Bbl)	$22.34	$21.43	$23.34
Natural gas (per Mcf)	3.16	3.73	3.84
Combined volumes (per BOE)	21.72	21.64	23.29
AVERAGE COSTS (PER BOE):			
Lease Operating Expenses:			
Direct lifting costs	$ 4.15	$ 4.00	$ 3.99
Production, ad valorem, and severance taxes	2.12	2.20	3.24
Depletion, depreciation, and amortization	4.67	5.05	4.72
General and administrative (excluding non-cash stock based compensation)	0.83	0.80	0.93

PRODUCING WELLS

The following table sets forth information at December 31, 2002 relating to the producing wells in which we owned a working interest as of that date. We also held royalty interests in 1,629 producing wells as of that date. Wells are classified as oil or natural gas wells according to their predominant production stream. Gross wells are the total number of producing wells in which we have an interest, and net wells are determined by multiplying gross wells by our average working interest.

	OIL WELLS			GAS WELLS		
	GROSS WELLS	NET WELLS	AVERAGE WORKING INTEREST	GROSS WELLS	NET WELLS	AVERAGE WORKING INTEREST
Cedar Creek Anticline	527	457	87%	12	3	25%
Crockett County	--	--	--	315	126	40%
Lodgepole	25	6	24%	--	--	--
Central Permian	1,144	142	12%	--	--	--
Other(2)	380	74	19%	81	12	15%
Total	2,076(1)	679	33%	408(1)	141	35%

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(1) Our total wells include 850 operated wells and 1,634 non-operated wells.

(2) Other includes our Indian Basin, Verden, Bell Creek and Paradox Basin properties, which individually represent less than 10% of our net production for 2002 and PV-10 at December 31, 2002.

ACREAGE

The following table sets forth information at December 31, 2002 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 Crockett, Verden, and CCA properties, which represent 40%, 35%, and 25% of our total undeveloped acreage, respectively.

These leases expire at various dates ranging from June 2003 to November 2010 with leases representing $352,000 of cost set to expire in 2003 if not developed.

	GROSS ACREAGE	NET ACREAGE
Developed acreage	179,223	128,442
Undeveloped acreage	65,039	49,179
Total	244,262	177,621

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. We should continue to have good results from drilling because most of our exposure is to infill drilling.

Productive wells are those that produce commercial quantities of hydrocarbons, exclusive of their capacity to produce a reasonable rate of return.

	YEAR ENDED DECEMBER 31,		
DEVELOPMENT WELLS	2002	2001	2000
Productive			
Gross	109.0	142.0	50.0
Net	95.3	105.6	37.2
Dry			
Gross	0.0	1.0	3.0
Net	0.0	1.0	1.1

PRESENT ACTIVITIES

As of December 31, 2002, the Company had a total of 5 gross (5 net) wells that had been spudded and were in varying stages of drilling operations. Also, there were 5 gross (4.8 net) wells that had reached total depth and were in varying stages of completion pending first production. Upgrades to facilities allowing for additional waterflood operations at North Pine in the Cedar Creek Anticline were also underway, as part of the ongoing North Pine waterflood reactivation program.

CEDAR CREEK ANTICLINE HIGH-PRESSURE AIR INJECTION LIMITED SCALE PROGRAM

In addition to the conventional development operations planned for 2003, the Company is currently in Phase I of the High-Pressure Air Injection ("HPAI") program in the Pennel Unit on the Cedar Creek Anticline. As the name suggests, 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. In June 2002, Encore began injecting air into the Red River U4 reservoir in a portion of the Pennel Unit of the CCA. Prior to beginning the air injection program, the project area was producing 360 gross barrels of oil per day. The project is currently producing an additional 100 gross barrels of oil per day, which the Company believes is due to the high-pressure air injection process.

Due to these early positive results, the Company is evaluating expanding the process in the Pennel, Coral Creek, and Little Beaver units on the CCA. We believe that High-Pressure Air Injection will generate a higher rate of return than other types of tertiary processes on the Cedar Creek Anticline. If the HPAI technology can be applied throughout the Cedar Creek Anticline, we believe it has the potential to yield significant new reserves. We are currently considering an additional $25.0 million in 2003 for High-Pressure Air Injection. The potential $25.0 million investment will be to implement the second phase of a four phase program in the Pennel and Coral Creek Red River U4 zones. The Red River U4 zone is the same zone where HPAI has been successfully implemented on the Cedar Creek Anticline in adjacent fields. In addition, we are studying another program on the Cedar Creek Anticline for our Little Beaver field, the southern most field in the CCA.

Readers and investors should note that we implemented a limited scale program and the results are highly prospective. While management is enthusiastic about the program, continued success of the program, as well as the amount of additional production and reserves attributable to the program, if any, cannot be predicted with certainty at this time.

DELIVERY COMMITMENTS AND MARKETING

Our oil and natural gas production is principally sold to end users, marketers, refiners, and other purchasers having access to nearby pipeline facilities. In areas where there is no practical access to pipelines, oil is trucked to storage facilities. Our marketing of oil and natural gas can be affected by factors beyond our control, the potential effects of which cannot be accurately predicted. For the fiscal year 2002, our largest purchasers included ConAgra and Equiva Trading Company (a joint venture between Shell and

Texaco), which respectively accounted for 16% and 10% of total oil and natural gas sales. Management is of the opinion that the loss of any one purchaser would not have a material adverse effect on its ability to market our oil and natural gas production.

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, to evaluate and select suitable properties, implement advanced technologies, and to 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 Encore. 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 charged 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. Encore 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 the Company's properties and the direct access to end-user markets, the future impact of these regulations on marketing Encore's production or on its 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 Encore's 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. Encore's 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.

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 Encore is in substantial compliance with applicable environmental laws and regulations. To date, we have not expended any material amounts to comply with such regulations, and management does not currently anticipate that future compliance will have a materially adverse effect on the consolidated financial position or results of operations of Encore.

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 which 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 OF THE COMPANY

The Company had 108 employees as of December 31, 2002, 46 of which are field personnel. None of the employees are represented by any union. The Company considers its relations with its employees to be good.

INTERNET ADDRESS

We make available electronically, free of charge through our Internet website address (www.encoreacq.com), our annual reports on Form 10-K, quarterly reports on Form 10-Q, current reports on Form 8-K, and amendments to those reports filed with the Securities and Exchange Commission (the "SEC") pursuant to Section 13(a) of the Exchange Act as soon as reasonably practicable after we electronically file such material with the SEC. These reports are directly accessible on the Internet at www.shareholder.com/encore/edgar.cfm.

PROPERTIES

NATURE OF OUR OWNERSHIP INTERESTS

We own interests in oil and natural gas properties located in Montana, North Dakota, Texas, New Mexico, Oklahoma, and Utah. Substantially all of our PV-10 reserve value at December 31, 2002 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.

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 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 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.

ROCKY MOUNTAIN PROPERTIES

Cedar Creek Anticline -- Montana and North Dakota

The Cedar Creek Anticline was purchased on June 1, 1999, and we have subsequently acquired additional working interests from various owners. Presently, we operate approximately 99% of the properties with an average working interest of approximately 87%.

The CCA is a major structural feature of the Williston Basin in southeastern Montana and northwestern North Dakota. The Company's acreage is concentrated on the "crest" of the CCA, giving us access to the greatest accumulation of oil in the structure. Our holdings extend for approximately 70 continuous miles across five counties in two states. The gross producing interval on the CCA is approximately 2,000 feet thick, and ranges in depth from approximately 7,000 feet to 9,000 feet.

Since taking over operations, along with subsequent additional acquired interests, the Company has increased production 67% on the CCA from 7,807 BOE per day (average June, 1999) to 13,060 BOE per day (average 4Q, 2002). We have accomplished this ongoing production growth through a combination of additional acquisition of interests; detailed attention to the existing wellbores; the addition of strategically positioned new wellbores; and the highly successful application of horizontal re-entry drilling. In 2002, we drilled 96 gross wells on the CCA, representing $71.7 million of cost. Of these, 63 were horizontal re-entry wells which both reestablished production from non-producing wells, and added additional barrels from existing producing wells. The average daily production from the CCA was 12,354 BOE per day for 2002.

Our outlook for sustained production growth on the CCA remains strong. The Company plans to continue the development of the reserve base through currently identified opportunities, and those that result from the knowledge gained through continued study and the drilling and exploitation efforts ongoing on these properties.

The CCA represents 75% of our total proved reserves as of December 31, 2002. The CCA represents the Company's most valuable asset today and in the foreseeable future. A large portion of the Company's future success revolves around future exploitation and production from the property.

Lodgepole -- Stark County, North Dakota

The Lodgepole properties were purchased on March 31, 2000. The properties consist of working and overriding royalty interests in several geographically concentrated fields. Approximately 98% of our interests are non-operated; the largest of which is the Eland Unit in which the Company owns a 26% working interest.

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 2,238 BOE per day for 2002.

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 2003 and a few years beyond.

Bell Creek -- Powder River and Carter Counties, Montana

The Bell Creek properties, located in the Powder River Basin of southeastern-most Montana, were purchased on November 29, 2000. The Company operates 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. The average daily production from the Bell Creek properties was 354 BOE per day for 2002. We believe this property has the potential for significant tertiary recovery in the future.

Paradox Basin -- San Juan County, Utah

On August 29, 2002 the Company completed an acquisition of interests in oil and natural gas properties in southeast Utah's Paradox Basin. The properties are divided between two prolific oil producing units: the Ratherford Unit operated by ExxonMobil and the Aneth Unit operated by ChevronTexaco. The working interest and net revenue interest in the Ratherford Unit are 11.06% and 9.68%, respectively, and the working interest and the net revenue interest in the Aneth Unit are 13.37% and 11.43%, respectively. The average net production to Encore since the acquisition is approximately 871 BOE per day. We believe these properties have horizontal redevelopment, secondary development, and tertiary recovery potential.

PERMIAN AND ANADARKO BASIN PROPERTIES

Crockett -- Crockett County, Texas

The Crockett properties were purchased on March 30, 2000. The Company has acquired small additional working interests subsequent to the initial acquisition. The properties, located in the southern portion of the Permian Basin of West Texas consist primarily of three field groupings located near the town of Ozona, Texas. The Company operates approximately 52% of the Crockett properties, and we own a large interest in a significant number of the properties that we do not operate.

Production comes mainly from the prolific Canyon and Strawn Formations. Both formations contain multiple pay intervals, and continued development opportunities remain on these properties. In 2002, we invested approximately $0.6 million drilling on the Crockett properties. Since acquiring these properties, we have increased production 23% from 8,700 Mcfe per day (average daily 2000) to 10,682 Mcfe per day (average daily 2002). The Crockett properties are the Company's most significant producers of natural gas.

In 2003, an active development drilling program is expected on our non-operated properties. The operator expects to drill approximately 12 wells in 2003 which are included in our 2 rig 40 well program in the Permian Basin.

Indian Basin -- Eddy County, New Mexico

The Indian Basin properties were purchased on August 24, 2000. The Company owns varied non-operated working interests in these properties (primary area operators are Marathon and ChevronTexaco), whose production is 95% natural gas. Located in the western portion of the Permian Basin in southeastern New Mexico, these properties produce from multiple zones in the Pennsylvanian Formation. The average daily production from the Indian Basin properties was 3,242 Mcfe per day for 2002.

Verden -- Caddo and Grady Counties, Oklahoma

The Verden properties were purchased on August 24, 2000. The Company owns various operated and non-operated interests in these properties. Located in the Anadarko Basin of central Oklahoma, production is primarily natural gas from the deep (below 15,000 feet) prolific Springer Sands. We have participated in the drilling of four new wells in this area, and average daily production from the Verden properties was 4,401 Mcfe per day for 2002.

Central Permian -- Andrews, Ector, and Pecos Counties, Texas

The Central Permian properties were purchased from Conoco on January 4, 2002. These properties are located in the Permian Basin near Midland, Texas, and include two major operated fields: East Cowden Grayburg Unit and Fuhrman-Nix; and two non-operated fields: North Cowden and Yates. The properties are 94% oil. All of these fields contain multiple producing intervals. Average daily production from the Central Permian properties was 1,978 BOE per day in 2002.

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 the Company's acreage position in the Cedar Creek Anticline, our primary asset, is subject to net profits interests.

ITEM 3. LEGAL PROCEEDINGS

The Company is 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 the Company's stockholders during the fourth quarter ended December 31, 2002.

PART II

ITEM 5. MARKET FOR REGISTRANT'S COMMON EQUITY AND RELATED STOCKHOLDER MATTERS

The Company's Common Stock, $0.01 par value, is listed on the New York Stock Exchange and trades under the symbol "EAC". The following table sets forth quarterly high and low closing sales prices of the Company's Common Stock for each quarterly period of 2001 and 2002, since our initial public offering ("IPO") on March 8, 2001:

	HIGH	LOW
2002		
Quarter ended March 31	$15.00	$12.50
Quarter ended June 30	17.25	14.65
Quarter ended September 30	17.50	15.20
Quarter ended December 31	19.05	13.88
2001		
Quarter ended March 31	$14.55	$11.19
Quarter ended June 30	17.56	11.25
Quarter ended September 30	15.20	11.69
Quarter ended December 31	14.73	12.30

On March 14, 2003, the Company had approximately 1,300 shareholders of record.

DIVIDENDS

No dividends have been declared or paid on the Company's 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 any future dividends may also be restricted by future agreements with our lenders.

ITEM 6. SELECTED FINANCIAL DATA

The following selected consolidated financial data since inception 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,				PERIOD FROM INCEPTION (APRIL 22, 1998 THROUGH DECEMBER 31,
	2002	2001	2000	1999	1998
CONSOLIDATED STATEMENT OF OPERATIONS DATA:					
Revenues(1):					
Oil..........................	$ 134,854	$105,768	$ 92,441	$ 30,454	$ --
Natural gas..................	25,838	30,149	16,509	810	--
Total revenues................	$ 160,692	$135,917	$108,950	$ 31,264	$ --
Net income (loss).............	$ 37,685(2)	$ 16,179(3)	$ (2,135)(4)	$ 3,005	$(1,010)
Net income (loss) per common share:					
Basic........................	$ 1.25	$ 0.56	$ (0.09)	$ 0.13	$ (0.08)
Diluted......................	1.25	0.56	(0.09)	0.13	(0.08)
Weighted average number of common shares outstanding:					
Basic........................	30,031	28,718	22,806	22,687	12,002
Diluted......................	30,161	28,723	22,806	22,687	12,002
CONSOLIDATED STATEMENT OF CASH FLOWS DATA:					
Cash provided by (used by):					
Operating activities........	$ 91,509	$ 80,212	$ 44,508	$ 9,759	$ (949)
Investing activities........	(159,316)	(89,583)	(99,236)	(201,701)	(289)
Financing activities........	80,749	8,610	49,107	194,972	4,705
PRODUCTION:					
Oil (Bbls)..................	6,037	4,935	3,961	1,796	--
Gas (Mcf)...................	8,175	8,078	4,303	180	--
Combined (BOE)..............	7,399	6,281	4,678	1,826	--
AVERAGE SALES PRICE:					
Oil ($/Bbl).................	$ 22.34	$ 21.43	$ 23.34	$ 16.96	$ --
Gas ($/Mcf).................	3.16	3.73	3.84	4.50	--
Combined ($/BOE)............	21.72	21.64	23.29	17.12	--
COSTS PER BOE:					
Direct lifting costs........	$ 4.15	$ 4.00	$ 3.99	$ 4.60	$ --
Production and severance taxes....................	2.12	2.20	3.24	2.97	--
General and administrative (excluding non-cash stock based compensation)......	0.83	0.80	0.93	2.22	--
Depletion, depreciation, and amortization............	4.67	5.05	4.72	2.89	--

	YEAR ENDED DECEMBER 31, 2002	2001	2000	1999	PERIOD FROM INCEPTION (APRIL 22, 1998 THROUGH DECEMBER 31, 1998
RESERVES:					
Oil (Bbls)	111,674	91,369	78,910	69,299	--
Gas (Mcf)	99,818	75,687	72,970	10,940	--
Combined (BOE)	128,310	103,983	91,072	71,122	--

	AT DECEMBER 31, 2002	2001	2000	1999	1998
CONSOLIDATED BALANCE SHEET DATA:					
Working capital	$ 12,489	$ 1,107	$(15,275)	$ 5,126	$3,419
Total assets	549,896	402,000	343,756	215,571	3,751
Total debt	166,000	79,107	162,045	99,250	--
Stockholders' equity	296,266	269,302	147,811	102,422	3,695

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(1) For the years ended December 31, 2002, 2001, 2000, and 1999 the Company reduced revenue for the payments of the net profits interests by $2.0 million, $2.8 million, $11.5 million, and $4.4 million, respectively.

(2) Net income for the year ended December 31, 2002 includes a $0.2 million extraordinary loss on early extinguishment of debt, which affects its comparability with other periods presented.

(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 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

SPECIAL NOTE REGARDING FORWARD-LOOKING STATEMENTS

Our disclosure and analysis in this Report contains some forward-looking statements. Forward-looking statements give our current expectations or forecasts of future events. You can identify these 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", "believe", and other words and terms of similar meaning in connection with any discussion of future operating or financial performance. In particular, these include, among other things, statements relating to:

- amount, nature, and timing of capital expenditures;

- drilling of wells;

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

- increases in proved reserves;

- operating costs and other expenses;

- cash flow and anticipated liquidity;

- prospect exploitation and property acquisitions; and

- marketing of oil and natural gas.

Any or all of our forward-looking statements in this Report may turn out to be wrong. They can be affected by inaccurate assumptions we might make or by known or unknown risks and uncertainties. Many factors mentioned in our discussion in this Report would be important in determining future results. Actual future results may vary materially. Factors that could cause our results to differ materially from the results discussed in the forward-looking statements include the following:

- the risks associated with operating in one or two major geographic areas;

- the risks associated with drilling of oil and natural gas wells in our exploitation efforts;

- our ability to find, acquire, market, develop, and produce new properties;

- oil and natural gas price volatility;

- uncertainties in the estimation of proved reserves and in the projection of future rates of production and timing of exploitation expenditures;

- operating hazards attendant to the oil and natural gas business;

- drilling and completion risks that are generally not recoverable from third parties or insurance;

- potential mechanical failure or underperformance of significant wells;

- climatic conditions;

- availability and cost of material and equipment;

- actions or inactions of third-party operators of our properties;

- our ability to find and retain skilled personnel;

- availability of capital;

- the strength and financial resources of our competitors;

- regulatory developments;

- environmental risks; and

- general economic conditions.

When you consider these forward-looking statements, you should keep in mind these risk factors and the other cautionary statements in this Report.

DESCRIPTION OF CRITICAL ACCOUNTING POLICIES

OIL AND NATURAL GAS PROPERTIES

We utilize the successful efforts method of accounting for our oil and natural gas properties. Under this method, all development and acquisition costs of proved properties are capitalized and amortized on a unit-of-production basis over the remaining life of proved developed reserves or proved reserves, as applicable. Exploration expenses, including geological and geophysical expenses and delay rentals, are charged to expense as incurred. Costs of drilling exploratory wells are initially capitalized, but charged to expense if and when the well is determined to be unsuccessful. 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. 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. 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 financial statements. Natural gas volumes are converted to equivalent barrels at the rate of six Mcf to one barrel.

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 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. Any impairment charge incurred is recorded in accumulated depletion, depreciation, and amortization ("DD&A") to reduce our recorded basis in the asset. Each part of this calculation is subject to a large degree of management judgment, including the determination of property's reserves, future cash flows, and fair value.

Management's assumptions used in calculating reserves or regarding the future cash flows or fair value of our properties are subject to change in the future. Any change could cause impairment expense to be recorded, reducing our net income and our basis in the related asset. 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. There can be no assurance that the proved reserves will be developed within the periods estimated or that prices and costs will 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. Additionally, as management's views related to future prices change, this changes the calculation of future net cash flows and also affects fair value estimates. Changes in either of these amounts will directly impact the calculation of impairment.

DD&A expense is also directly affected by the Company's reserve estimates. Any change in reserves directly impacts the amount of DD&A expense the Company recognizes in a given period. Assuming no other changes, such as an increase in depreciable base, as the Company's 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, 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 and the subsequent three quarters of the new year.

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 revenues. 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.

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.

Prior to January 1, 2001, these agreements were accounted for as hedges using the deferral method of accounting. Unrealized gains and losses were generally not recognized until the physical production required by the contracts was delivered. At the time of delivery, the resulting gains and losses were recognized as an adjustment to oil and natural gas revenues. The cash flows related to any recognized gains or losses associated with these hedges were reported as cash flows from operations. If the hedge was terminated prior to maturity, gains or losses were deferred and included in income in the same period as the physical production required by the contracts was delivered.

We also use derivative instruments in the form of interest rate swaps, which hedge our risk related to interest rate fluctuation. Prior to January 1, 2001, these agreements were accounted for as hedges using the accrual method of accounting. The differences to be paid or received on swaps designated as hedges were included in interest expense during the period to which the payment or receipt related. The cash flows related to recognized gains or losses associated with these hedges were reported as cash flows from operations.

Effective January 1, 2001, the Company adopted Statement of Financial Accounting Standards No. 133 ("SFAS 133"), "Accounting for Derivative Instruments and Hedging Activities". This standard required us to 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 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 the Company's derivative financial instruments qualify for hedge accounting. The only exceptions at December 31, 2002 are a written oil put contract representing 500 Bbls/D for 2003 and several interest rate swap contracts. In accordance with the provisions of SFAS 133, these are marked-to-market through earnings each quarter. If oil prices or LIBOR interest rates were to change dramatically and cause a material increase or decrease in the market value of these contracts, the change would be recognized in earnings immediately.

Currently, all of the Company's derivative financial instruments that qualify for hedge accounting 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 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 into earnings immediately. While management does not anticipate changing the designation of any of our current derivative contracts as hedges, factors beyond our control could 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 deemed creditworthy and non-performance under the terms of the contract was likely. If any of our contracts no longer qualify for hedge accounting, this potentially could induce high earnings volatility, as any future changes in the market value of the contract would then be marked-to-market through earnings.

NEW ACCOUNTING STANDARDS

In August 2001, the FASB issued Statement of Financial Accounting Standards No. 143 ("SFAS 143"), Accounting for Asset Retirement Obligations, which the Company will be required to adopt 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 adjustment to record (i) a $4.0 million increase in the carrying values of proved properties, (ii) a $2.1 million decrease in accumulated depletion, depreciation, and amortization, and (iii) a $5.2 million increase in other non-current liabilities, and (iv) a gain of $0.9 million, net of tax, as a cumulative effect of accounting change on January 1, 2003.

In April 2002, the FASB issued SFAS 145, "Rescission of FASB Statements No. 4, 44, and 64, Amendment of FASB Statement No. 13, and Technical Corrections". Under Statement 4, all gains and losses from extinguishment of debt were required to be aggregated and, if material, classified as an extraordinary item, net of related income tax effect. This Statement eliminates Statement 4 and, thus, the exception to applying Opinion 30 to all gains and losses related to extinguishments of debt. As a result, gains and losses from extinguishment of debt should be classified as extraordinary items only if they meet the criteria in Opinion 30. Applying the provisions of Opinion 30 will distinguish transactions that are part of an entity's recurring operations from those that are unusual or infrequent or that meet the criteria for classification as an extraordinary item. This statement is effective for Encore beginning January 1, 2003, at which time the extraordinary loss on extinguishment of debt recorded in the second quarter of 2002 will be reclassified to operating income.

COMPARISON OF 2002 TO 2001

Set forth below is our comparison of operations during the year ended December 31, 2002 with the year ended December 31, 2001.

Revenues and Production. For the year ended December 31, 2002, revenues increased $24.8 million. The following table illustrates the primary components of oil and natural gas revenue for the years ended December 31, 2002 and 2001, as well as each year's respective oil and natural gas volumes (in thousands except per unit amounts):

	YEAR ENDED DECEMBER 31,					
	2002		2001		DIFFERENCE	
	REVENUE	$/UNIT	REVENUE	$/UNIT	REVENUE	$/UNIT
REVENUES:						
Oil wellhead..................	$141,119	$23.38	$114,723	$23.25	$26,396	$ 0.13
Oil hedges...................	(6,265)	(1.04)	(8,955)	(1.82)	2,690	0.78
Total Oil Revenues.........	$134,854	$22.34	$105,768	$21.43	$29,086	$ 0.91
Natural gas wellhead.........	$ 24,803	$ 3.03	$ 34,014	$ 4.21	$(9,211)	$(1.18)
Gas hedges...................	1,035	0.13	(3,865)	(0.48)	4,900	0.61
Total Gas Revenues.........	$ 25,838	$ 3.16	$ 30,149	$ 3.73	$(4,311)	$(0.57)

	PRODUCTION	AVERAGE NYMEX $/UNIT	PRODUCTION	AVERAGE NYMEX $/UNIT	PRODUCTION	AV N $/
OTHER DATA:						
Oil (Bbls)..................	6,037	$26.08	4,935	$25.92	1,102	$
Gas (Mcf)....................	8,175	3.36	8,078	4.06	97	(
Combined (BOE)...............	7,399		6,281		1,118	

Oil revenues increased $29.1 million in 2002 over 2001 primarily due to an increase in oil volumes, while the net wellhead price received remained relatively flat. Oil volumes increased 1,102 MBbls from 2001 to 2002 due to the Central Permian and Paradox Basin acquisitions, as well as increased production from the Company's successful development drilling program. Wellhead oil revenues were reduced by $2.0 million and $2.7 million in 2002 and 2001, respectively, for the net profits interests payments held by others in the CCA. Total oil revenues were further increased by a decrease in hedge payments, which were $2.7 million lower.

Natural gas revenues decreased in 2002 by $4.3 million due to a 28% decrease in the net wellhead price received, from $4.21 in 2001 to $3.03 in 2002, with essentially flat production. This price decline is consistent with the NYMEX decline from $4.06 to $3.36 over the same period. The Company recovered a portion of the natural gas price decline through its hedges, which generated net receipts of $1.0 million in 2002 versus net payments of $3.9 million in 2001. These hedging receipts are a direct result of the decrease in the average NYMEX price for natural gas.

For 2003 we anticipate increased production related to our anticipated $105 million capital drilling program. Unless changes are made to our planned drilling activities or another acquisition is made, production should be approximately 7.7 million BOE for 2003.

Prices received for oil and natural gas production are largely based on current market prices, which are beyond our control. During 2002, prices were trending upward. The NYMEX strip pricing at December 31, 2002 indicates higher oil and natural gas prices in 2003. We have based our 2003 forecasts on the assumptions of $23.50 per Bbl and $3.75 per Mcf NYMEX prices. At these assumed prices, we have forecasted hedge contract payments of approximately $2.3 million for oil and receipts of $0.6 million for natural gas. 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 of $0.7 million for oil and $0.02 million for natural gas. These payments are highly dependent on the level of drilling in the CCA and commodity prices, and thus, any change in the level of drilling or market 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 $23.50 for oil and $3.75 for natural gas, the Company will not be able to fund the budgeted $105 million drilling program for 2003 through internally generated cash flow and available cash. In this case, the Company would have to borrow money under our existing revolving credit facility, seek additional equity, or curtail the capital program. If drilling is curtailed or ended, future cash flows could be materially negatively impacted.

Direct lifting costs. Direct lifting costs of the Company for the year ended December 31, 2002 increased as compared to 2001 by $5.5 million. The increase in direct lifting costs resulted from the increase in volumes as a result of our 2002 Central Permian and Paradox Basin acquisitions and our successful drilling program. See "-- Revenues and Production" on page 21. On a per BOE basis, direct lifting costs increased from $4.00 in 2001 to $4.15 in 2002 primarily due to higher per BOE lifting costs for our 2002 acquisitions.

For 2003 we anticipate an increase in total direct lifting costs, as well as on a per BOE basis. We anticipate this increase due to a full year of production at our Paradox Basin properties which have a higher per BOE operating costs than our Company's historical average for direct lifting costs, as well as expected higher electricity costs, one of the largest components of direct lifting costs, on our Permian and

CCA properties. We have projected total direct lifting costs of approximately $37.6 million or $4.89 per BOE for 2003.

Production, ad valorem, and severance taxes. Production, ad valorem, and severance taxes for the year ended December 31, 2002 increased as compared to 2001 by approximately $1.8 million. The increase is a direct result of the increase in wellhead revenue. See "-- Revenues and Production" on page 21. As a percentage of oil and natural gas revenues (excluding the effects of net profits and hedges), production, ad valorem, and severance taxes increased slightly from 9.1% to 9.3% from 2001 to 2002.

For 2003 total production, ad valorem, and severance taxes will depend in a large part on prevailing prices. However, the production, ad valorem, and severance tax rate should remain relatively constant at an estimated 9.6% of wellhead revenues. As production is forecast to increase, similar prices in 2003 as in 2002 would cause an increase in total production, ad valorem, and severance taxes. Additionally, if prices continue to stay above $30 per Bbl we will temporarily lose production and severance tax incentives in Montana and North Dakota, which would cause our tax rates to increase in 2003.

Depletion, depreciation, and amortization ("DD&A") expense. DD&A expense increased by approximately $2.8 million in 2002. This increase was due to a 1.1 MMBOE increase in production volumes, partially offset by a decrease in the DD&A rate per BOE. See "-- Comparison of 2002 and 2001 -- Revenues and Production" on page 21. The average DD&A rate decreased from $5.05 per BOE of production during 2001 to $4.67 per BOE in 2002. The increase in volumes caused a $5.6 million increase in related DD&A expense, while the decrease in the DD&A rate caused a $2.8 million decrease. The decrease is attributable to upward reserve revisions due to higher prices.

We anticipate the total DD&A expense in 2003 to increase due to increased production resulting from the Paradox Basin acquisition and our planned 2003 capital expenditures of $105 million. Assuming capital expenditures that do not differ significantly from our budgeted amount, we expect our DD&A rate for 2003 to be approximately $4.15 per BOE. This per BOE decrease from 2002 is primarily due to the effects of Statement of Financial Accounting Standards No. 143, "Accounting for Asset Retirement Obligations" and higher proved reserve volumes at December 31, 2002. This rate could vary significantly based on actual capital expenditures, production rates, and any acquisition that closes in 2003. 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.

General and administrative (G&A) expense. G&A expense increased $1.1 million in 2002 (excluding non-cash stock based compensation of $9.6 million in 2001). The increase in G&A resulted from the additional staff necessary after the Permian and Paradox Basin acquisitions to manage, expand, and exploit our growing asset base. On a per BOE basis, G&A expense remained relatively flat at $0.83 during 2002 as compared to $0.80 during 2001.

We have forecast approximately $6.8 -- $7.3 million for general and administrative expenses in 2003. This represents a modest increase of $0.6 to $1.1 million from 2002. The increase will result from higher insurance, rent, salaries, and hiring additional support staff necessary for our growing asset base.

Other operating expense. Other operating expense for the year ended December 31, 2002 increased as compared to 2001 by approximately $0.8 million. This amount primarily consists of 2001 severance payment obligations to former employees of the Company, as well as transportation costs, namely pipeline fees paid to third parties, geological and geophysical expenses, and delay rentals. The increase is due to higher transportation costs and geological and geophysical expenses in 2002, which more than offset the lack of severance payments in 2002.

For 2003, we anticipate other operating expense to be approximately $1.0 to $1.5 million.

Interest expense. Interest expense for the year ended December 31, 2002 increased $6.3 million over 2001. The increase in interest expense is primarily due to increased levels of debt, amortization of hedge loss (see below), and a higher weighted average interest rate in 2002 as compared to 2001. On June 25, 2002, the Company issued $150.0 million in 8 3/8% senior subordinated notes, and used most of the

proceeds to repay all amounts outstanding under the previous credit facility, terminated the previous credit facility, and entered into a new revolving credit facility. See "-- Liquidity and Capital Resources" on page 29. For 2002, the weighted average debt balance was $149.7 million, compared with $89.3 million for 2001. Additionally, the weighted average interest rate, including hedges, in 2002 was 8.2%, while it was 6.8% in 2001. The higher weighted average interest rate is due to a higher fixed rate on these notes as compared to the floating rate debt outstanding previously.

At the time the previous credit facility was terminated, the Company had three interest rate swaps outstanding, with a notional amount of $30.0 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. The unrealized loss of $3.8 million at June 25, 2002, which was recognized in accumulated other comprehensive income, is being amortized to interest expense over the original life of the swaps. We amortized $1.6 million of this loss to interest expense during 2002.

The following table illustrates the components of interest expense for 2002 and 2001 (in thousands):

	2002	2001	DIFFERENCE
8 3/8% senior subordinated notes	$ 6,488	$ --	$ 6,488
Facilities	2,260	4,596	(2,336)
Burlington note	--	389	(389)
Hedge settlements	1,249	717	532
Hedge loss amortization	1,619	--	1,619
Debt issuance cost	314	120	194
Fees and other	376	219	157

Total	$12,306	$6,041	$ 6,265

Non-cash stock based compensation expense. Non-cash stock based compensation expense decreased from $9.6 million for 2001 to zero in 2002. This non-cash stock based compensation expense is associated with the purchase by our management stockholders of Class A common stock under our management stock plan adopted in August 1998 and was recorded as compensation in accordance with variable plan accounting under Accounting Principles Board Opinion No. 25, Accounting for Stock Issued to Employees ("APB 25"). The $9.6 million of non-cash compensation expense recorded in the first quarter of 2001 represents the final amount of expense to be recorded related to the Class A stock.

At the end of the fourth quarter of 2002, the Company issued 129,328 shares of restricted stock to all current employees. Of these, 77,901 shares vest over a five year period evenly in years three, four, and five 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 as shown in the table below. The remaining 51,427 shares were issued to four members of senior management and also vest over a five year period evenly in years three, four, and five. 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. The table below reflects the

estimated expense related to the restricted stock grant to be recorded in the future by year based on the Company's stock price at December 31, 2002 (in thousands).

PERIOD	FIXED COMPENSATION EXPENSE	ESTIMATED VARIABLE COMPENSATION EXPENSE	TOTAL COMPENSATION EXPENSE
2003	$ 377	$249	$ 626
2004	377	249	626
2005	377	249	626
2006	216	143	359
2007	96	63	159
Total	$1,443	$953	$2,396

Derivative fair value gain/loss. The derivative fair value gain of $0.9 million in 2002 represents the ineffective portion of the mark-to-market loss on our derivative hedging instruments, as well as the mark-to-market loss on our two short puts outstanding at December 31, 2002 and our interest rate swap settlements subsequent to the issuance of the senior subordinated notes on June 25, 2002. See "Item 7A. Quantitative and Qualitative Disclosures about Market Risk -- Commodity Price Sensitivity" on page 32.

Currently this line item on the statement of operations is primarily dependent on the futures price of oil and LIBOR interest rates. This is due to the fact that, currently, the main components are the mark-to-market movement and settlements of our short oil put and our interest rate swaps.

Bad Debt Expense. 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 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 us by Enron, for the year ended December 31, 2001, we have recorded a charge to bad debt expense for the full amount of the receivable, $7.0 million, and recorded a related allowance on the receivable of $7.0 million. Any ultimate recovery on the Enron receivable will be recognized in earnings if and when management believes recovery of the asset is probable.

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. According to the provisions of SFAS 133, this gain must be recorded in other comprehensive income until such time as the original hedged production affects income. As a result, at December 31, 2001, we had $4.8 million in gross unrecognized gains in other comprehensive income that are being reversed into earnings during 2002 and 2003. The following table illustrates the current and future amortization of this amount to revenue (in thousands):

PERIOD	OIL	GAS	TOTAL
2002	$2,822	$1,594	$4,416
2003	401	18	419
Total	$3,223	$1,612	$4,835

Impairment of Oil and Gas Properties. Throughout 2001, futures prices for oil and natural gas continued to decline from their December 31, 2000 levels. The SEC price case used for our 2000 reserve

estimate was $26.80 per Bbl and $9.77 per Mcf dropping to $19.84 per Bbl and $2.57 per Mcf for the 2001 estimate. Although the SEC price case does not necessarily coincide with management's estimates of future prices, this indicated the need to assess our oil and natural gas properties for any possible impairment. Thus, we compared the undiscounted future cash flows for each of our oil and natural gas properties to their net book value, which indicated the need for an impairment charge on certain properties. We then compared the net book value of the impaired assets to their estimated fair value, which resulted in a write-down of the value of proved oil and gas properties of $2.6 million. Fair value was determined using estimates of future production volumes and estimates of future prices we might receive for these volumes discounted back to a present value using a rate commensurate with the risks inherent in the industry.

We performed a similar review at December 31, 2002 and 2000 and determined no impairment charge was necessary.

Future impairment charges could result based on changes in the Company's estimated reserves, management's estimate of future prices, or management's fair value estimate of our properties. If oil and natural gas prices were to decrease in the future, our reserves could be negatively impacted and/or management's estimate of either future cash flows or fair value of our properties could change. Any of these results could indicate the need for additional impairment charges.

COMPARISON OF 2001 TO 2000

Set forth below is our comparison of operations during the year ended December 31, 2001 with the year ended December 31, 2000.

Revenues and Production. For the year ended December 31, 2001, revenues increased $27.0 million. The following table illustrates the primary components of oil and natural gas revenue for the years ended December 31, 2001 and 2000, as well as each year's respective oil and natural gas volumes (in thousands except per unit amounts):

	YEAR ENDED DECEMBER 31,					
	2001		2000		DIFFERENCE	
	REVENUE	$/UNIT	REVENUE	$/UNIT	REVENUE	$/UNIT
REVENUES:						
Oil wellhead........................	$114,723	$23.25	$112,300	$28.35	$ 2,423	$(5.10)
Oil hedges..........................	(8,955)	(1.82)	(19,859)	(5.01)	10,904	3.19
Total Oil Revenues................	$105,768	$21.43	$ 92,441	$23.34	$13,327	$(1.91)
Natural gas wellhead................	$ 34,014	$ 4.21	$ 19,687	$ 4.58	$14,327	$(0.37)
Gas hedges..........................	(3,865)	(0.48)	(3,178)	(0.74)	(687)	0.26
Total Gas Revenues................	$ 30,149	$ 3.73	$ 16,509	$ 3.84	$13,640	$(0.11)

	PRODUCTION	AVERAGE NYMEX $/UNIT	PRODUCTION	AVERAGE NYMEX $/UNIT	PRODUCTI
OTHER DATA:					
Oil (Bbls)..........................	4,935	$25.92	3,961	$30.13	974
Gas (Mcf)...........................	8,078	4.06	4,303	3.60	3,775
Combined (BOE)......................	6,281		4,678		1,603

Oil revenues increased $13.3 million from 2000 to 2001. As illustrated above, this was due to an increase in oil volumes offset by a decrease in net price per Bbl. Oil volumes increased 974 MBbls from 2000 to 2001 due to a full year of production from the acquisitions completed during 2000, as well as increased production from the Company's successful development drilling program. This increase in

production added $2.4 million in wellhead revenue despite a decrease of $5.10 per barrel in the wellhead price received. The decrease in wellhead price resulted primarily from a decrease in the overall market price for oil in 2001 as reflected in the $4.21 per Bbl decrease in the average NYMEX price from 2000 to 2001. Oil revenues were reduced by $2.7 million and $11.2 million in 2001 and 2000, respectively, for the net profits interests payments held by others in CCA. The decrease in net profits interests payments in 2001 was due to increased capital activity, which reduces the net profits interests payments. The decrease in wellhead oil revenues was offset by a decrease in payments made for hedging, which decreased $10.9 million. The Company's hedging activities are not a component of the expenses deducted in calculating net profits interest payments. The decrease in hedging payments is a direct result of the decrease in the average NYMEX price for oil.

Natural gas revenues increased from 2000 to 2001 by $13.6 million due to a 3,775 MMcf increase in production, while net price received decreased by $0.11. The increase in volumes is due to a full year of production for the acquisitions completed in 2000, as well as increased production in the CCA and Crockett County properties due to successful development drilling. Wellhead price received decreased $0.37 per Mcf, while the average NYMEX price increased $0.46 per Mcf. This is the result of higher prices received in relation to NYMEX for natural gas in the CCA versus the price discount received in the Indian Basin/Verden areas. Hedging payments decreased $0.26 per Mcf due to different hedges being in effect during 2001 than 2000.

Direct lifting costs. Direct lifting costs of the Company for the year ended December 31, 2001 increased as compared to 2000 by $6.5 million. The increase in direct lifting costs resulted from the increase in volumes related to the full year effect of our 2000 acquisitions and our successful drilling program, as well as an increase in direct lifting costs per BOE. See "-- Comparison of 2001 to 2000 -- Revenues and Production" on page 26. On a per BOE basis, direct lifting costs increased from $3.99 in 2000 to $4.00 in 2001 due to higher workover and contract labor costs in the CCA resulting from to the relatively harsh winter and the increased cost for services. Additionally, the Company invested $1.0 million related to workovers in Bell Creek, which was acquired in December 2000.

Production, ad valorem, and severance taxes. Production, ad valorem, and severance taxes for the year ended December 31, 2001 decreased as compared to 2000 by approximately $1.4 million. The decrease is a direct result of the decrease in wellhead revenue. See "-- Comparison of 2001 to 2000 -- Revenues and Production" on page 26. As a percentage of oil and natural gas revenues (excluding the effects of hedges), production, ad valorem, and severance taxes decreased from 10.6% to 9.1% from 2000 to 2001. This decrease was the result of a higher production, ad valorem, and severance tax rate in Montana associated with our CCA asset versus the lower tax rates in Texas, North Dakota, New Mexico, and Oklahoma associated with our Crockett County, Lodgepole, and Indian Basin/Verden assets. Thus, as the percentage of revenue from Crockett County, Lodgepole, and Indian Basin/Verden increased in 2001, the total production, ad valorem, and severance tax rate for all areas declined.

Depletion, depreciation, and amortization ("DD&A") expense. DD&A expense increased by approximately $9.6 million from 2000 to 2001. This increase was due to a 1.6 MMBOE increase in production volumes, as well as an increase in the

DD&A rate per BOE. See "-- Comparison of 2001 to 2000 -- Revenues and Production" on page 26. The average DD&A rate increased from $4.72 per BOE of production during 2000 to $5.05 per BOE in 2001. The increase in volumes caused a $6.4 million increase in related DD&A expense, while the increased DD&A rate caused a $3.2 million increase. The higher rate in 2001 is attributable to higher per BOE acquisition costs associated with the Crockett County, Lodgepole, Indian Basin/Verden, and Bell Creek acquisitions completed in 2000 as compared to the original rate associated with the Cedar Creek Anticline.

General and administrative (G&A) expense. G&A expense increased $0.7 million from 2000 to 2001 (excluding non-cash stock based compensation of $9.6 million and $26.0 million in 2001 and 2000, respectively). The increase in G&A resulted from the additional staff and lease space necessary for the Crockett County, Lodgepole, Indian Basin/Verden, and Bell Creek acquisitions completed in 2000. During 2001, the Company leased an additional floor at the corporate headquarters and incurred additional costs

related to being a publicly traded company. On a per BOE basis, G&A expense fell to $0.80 during 2001 from $0.93 during 2000. This reduction resulted as fixed costs were spread over a greater amount of production in 2001 as compared to 2000.

Other Operating Expense. The Company recorded $0.9 million of other operating expense in 2001 with no similar amount in 2000. This amount primarily consists of severance payments made during 2001 or accrued at December 31, 2001 to former employees of the Company, as well as transportation costs, namely pipeline fees paid to third parties. Additionally, geological and geophysical and delay rentals are recorded on this line in the statement of operations.

Interest expense. Interest expense for the year ended December 31, 2001 decreased $4.4 million from 2000 to 2001. The decrease in interest expense resulted primarily from the pay down of debt in conjunction with the Company's initial public offering. In addition the weighted average interest rate, including hedges, for 2001 was 6.8% compared to 7.4% for 2000. The following table illustrates the components of interest expense for 2001 and 2000 (in thousands):

	2001	2000	DIFFERENCE
Facility	$4,596	$ 9,693	$(5,097)
Burlington note	389	763	(374)
Hedges	717	(86)	803
Fees	339	120	219
Total	$6,041	$10,490	$(4,449)

Non-cash stock based compensation expense. Non-cash stock based compensation expense decreased from $26.0 million for 2000 to $9.6 million for 2001. This non-cash stock based compensation expense is associated with the purchase by our management stockholders of Class A common stock under our management stock plan adopted in August 1998 and was recorded as compensation in accordance with variable plan accounting under Accounting Principles Board Opinion No. 25, Accounting for Stock Issued to Employees ("APB 25"). The $9.6 million of 2001 non-cash compensation expense was recorded in the first quarter of 2001 and represents the final amount of expense to be recorded related to the Class A stock.

Derivative fair value loss. The derivative fair value loss of $0.7 million in 2001 represents the ineffective portion of the mark-to-market loss on our derivative hedging instruments, as well as the mark-to-market loss on our two short puts outstanding at December 31, 2001. These amounts are now being recorded as required by Statement of Financial Accounting Standards 133, "Accounting for Derivative Instruments and Hedging Activities" ("SFAS 133"). No similar amounts were recorded in 2000 as we adopted SFAS 133 effective January 1, 2001.

Bad Debt Expense. 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 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 us by Enron, for the year ended December 31, 2001, we have recorded a charge to bad debt expense for the full amount of the receivable, $7.0 million, and recorded a related allowance on the receivable of $7.0 million. Any ultimate recovery on the Enron receivable will be recognized in earnings when management believes recovery of the asset is probable.

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. According to the provisions of SFAS 133, this gain must be recorded in other comprehensive income until such time as the original hedged production affects income. As a result, at December 31, 2001, we had $4.8 million in gross unrecognized gains in other comprehensive income that will be reversed into earnings during 2002 and 2003. The following table illustrates the future amortization of this amount to revenue (in thousands):

PERIOD	OIL	GAS	TOTAL
2002	$2,822	$1,594	$4,416
2003	401	18	419
Total	$3,223	$1,612	$4,835

Impairment of Oil and Gas Properties. Throughout 2001, futures prices for oil and natural gas continued to decline from their December 31, 2000 levels. The SEC price case used for our 2000 reserve estimate was $26.80 per Bbl and $9.77 per Mcf dropping to $19.84 per Bbl and $2.57 per Mcf for the 2001 estimate. Although the SEC price case does not necessarily coincide with management's estimates of future prices, this indicated the need to assess our oil and natural gas properties for any possible impairment. Thus, we compared the undiscounted future cash flows for each of our oil and natural gas properties to their net book value, which indicated the need for an impairment charge on our Bell Creek properties. We then compared the net book value of the Bell Creek properties to their estimated fair value, which resulted in a write-down of the value of proved oil and gas properties of $2.6 million. Fair value was determined using estimates of future production volumes and estimates of future prices we might receive for these volumes discounted back to a present value using a rate commensurate with the risks inherent in the industry.

LIQUIDITY AND CAPITAL RESOURCES

Principal uses of capital have been for the acquisition and development of oil and natural gas properties.

During the year ended December 31, 2002, net cash provided by operations was $91.5 million, an increase of $11.3 million compared to 2001. This was due in large part to higher net income in 2002 as compared to 2001. Encore's operating cash flow is determined in a large part by commodity prices. Assuming moderate to high commodity prices, the Company's operating cash flow should remain positive for the foreseeable future. We anticipate that our capital expenditures will total approximately $105.0 million for 2003. 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 development and acquisition expenditures using internally generated cash flow, available cash, and our existing credit agreement.

At December 31, 2002, the Company had total assets of $549.9 million. Total capitalization was $462.3 million, of which 64.1% was represented by stockholders' equity and 35.9% by senior debt.

On June 25, 2002, the Company sold $150 million of 8 3/8% Senior Subordinated Notes maturing on June 15, 2012 (the "Notes") in a private offering exempt from registration requirements of the Securities Act of 1933 as amended. The offering was made through a private placement pursuant to Rule 144A. The Company received net proceeds of $145.6 million from the sale of the Notes, after deducting debt issuance costs. The proceeds were used to repay and retire the Company's prior credit facility ($143.0 million), to pay the fees and expenses related to the new revolving credit facility ($1.5 million), and to hold in reserve for the Paradox Basin acquisition ($1.1 million).

In connection with the issuance of the Notes, we entered into a registration rights agreement, dated June 19, 2002, with the initial purchasers of the Notes and entered into an indenture governing the Notes. The indenture limits our ability, among other things, to:

- incur additional indebtedness;
- pay dividends on our capital stock or redeem, repurchase or retire our capital stock or subordinated indebtedness;
- make investments;
- incur liens;
- create any consensual limitation on the ability of our restricted subsidiaries to pay dividends, make loans or transfer property;

- engage in transactions with affiliates;

- sell assets, including capital stock of our subsidiaries; and

- consolidate, merge or transfer assets.

Pursuant to the registration rights agreement, we filed a registration statement on Form S-4/A with the SEC, which was declared effective on December 6, 2002, with respect to the exchange of the Notes for registered notes having terms substantially identical in all material respects. On January 16, 2003, all of the Notes were exchanged for the registered notes, Encore's registered senior subordinated notes due June 15, 2012 were issued and the Notes were cancelled. The Company did not receive any proceeds from the exchange.

The registered notes are senior subordinated unsecured obligations of Encore. The registered notes mature on June 15, 2012. We pay interest on the registered notes semiannually on June 15 and December 15, beginning on December 15, 2002. The registered notes rank equal in right of payment with any of our future senior subordinated indebtedness and are subordinated in right of payment to our obligations under our revolving credit facility (see next paragraph) and of our other existing and future senior indebtedness. The payment of principal, interest, and premium on the registered notes is fully and unconditionally guaranteed, jointly and severally, on a senior subordinated basis, by our existing and some of our future restricted subsidiaries. We are entitled to redeem the registered notes in whole or in part on or after June 15, 2007 for the redemption price set forth in the registered notes. Prior to June 15, 2005, we are entitled to redeem the registered notes, in whole but not in part, at a redemption price equal to the principal amount of the registered notes plus a premium. There is no sinking fund for the notes. If we fail to comply with some of our obligations under the registration rights agreement relating to the registered notes, we will pay additional interest on the registered notes.

Concurrently with the issuance of the Notes, we entered into a new revolving credit facility with a syndicate of banks, which replaced our prior credit facility. All of our subsidiaries are guarantors of our revolving credit facility. The maximum amount available under our revolving credit facility is $300.0 million, which is secured by a first priority lien on our proved oil and natural gas reserves representing at least 80% of the present discounted reserve value. As of December 31, 2002, the amount available to us under our revolving credit facility is $220.0 million which may be increased and decreased subject to a borrowing base calculation. As of December 31, 2002, $16.0 million was outstanding under the new revolving credit facility. The maturity date is June 25, 2006.

We may choose between two base loan interest rates. The first base interest rate (the "ABR Rate") is a rate calculated as the highest of:

- the annual rate of interest announced by the Agent Bank as its "base rate"; and

- the federal funds effective rate plus 0.5%;

plus a margin of 0% to 0.75% based upon the level of borrowing. The second base rate (the "LIBOR Rate") is equal to the London InterBank offered rate plus a margin of 0% to 1.75% based upon the level of borrowing. In addition to the foregoing rates, we must pay a commitment fee on unused portions of the available borrowing base. Interest on ABR Rate loans is paid quarterly in arrears. At our election, interest periods for LIBOR Rate loans are one, three, six or twelve months, and interest is payable at the end of each interest period and at the end of each succeeding three month period.

Borrowings under our revolving credit facility are guaranteed by each of our subsidiaries and are secured by a mortgage of our oil and natural gas properties and a pledge of the capital stock and equity interests of our subsidiaries. We pay customary fees to the various banks and agents.

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

Our revolving credit facility contains a number of negative and financial covenants, all of which we were in compliance with as of December 31, 2002.

These covenants include, among others:

- a prohibition against incurring debt in excess of $15.0 million, except for borrowings under our revolving credit facility, the outstanding notes, and the exchange notes;

- a prohibition against paying dividends or purchasing or redeeming capital stock or prepaying indebtedness (including the outstanding notes and the exchange notes);

- a restriction on creating liens on our assets;

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

- restrictions on use of proceeds, investments, transactions with affiliates, changing our principal business, and incurring funding obligations under ERISA;

- a provision limiting oil and natural gas hedging transactions to a volume not exceeding 75% of anticipated production from proved reserves;

- a requirement that we maintain a ratio of consolidated current assets to consolidated current liabilities of not less than 1.0 to 1.0; and

- a requirement that we maintain a ratio of consolidated EBITDA (as defined in our revolving credit facility agreement) to the sum of consolidated net interest expense plus our letter of credit fees of not less than 2.5 to 1.0.

Based on current commodity conditions, the Company believes that its capital resources are adequate to meet the requirements of its business through 2004. Based on our anticipated capital investment programs, we expect to invest our internally generated cash flow to replace production and enhance our development programs. During 2003, we plan to invest approximately $105 million to exploit and develop existing core properties. The $105 million budgeted does not include the possible $25 million for additional high-pressure air-injection capital. See "Item 1 Business and Properties -- Present Activities -- Cedar Creek Anticline High-Pressure Air Injection Limited Scale Program" on page 9. Additional capital may be required to pursue acquisitions or other capital projects. Substantially all of these 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 on our outstanding hedges with our counter parties if the hedges reach a certain negative value. At December 31, 2002, the Company had an outstanding letter of credit with a counterparty in the amount of $2.3 million, which expired on January 31, 2003. If oil prices continue to rise, we could be required to make margin deposits or increase our outstanding letters of credits. Also, subsequent to December 31, 2002, the Company cash settled the two outstanding $30 million interest rate swaps at a cost of $4.3 million.

The following table illustrates the Company's contractual obligations outstanding at December 31, 2002:

	PAYMENTS DUE BY PERIOD				
CONTRACTUAL OBLIGATIONS	TOTAL	2003	2004 - 2005	2006 - 2007	THEREAFTER
8 3/8% Notes	$150,000	$ --	$ --	$ --	$150,000
Revolving Credit Facility	16,000	--	--	16,000	--
Operating Leases	3,801	959	1,938	691	213
Totals	$169,801	$959	$1,938	$16,691	$150,213

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, 2002, 2001, and 2000. Average equivalent prices for 2002, 2001, and 2000 were decreased by $0.70, $2.04, and $4.92 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 (PER BBL)	NATURAL GAS (PER MCF)	EQUIV. OIL (PER BOE)
NET PRICE REALIZATION WITH HEDGES			
Year ended December 31, 2002	$22.34	$3.16	$21.72
Year ended December 31, 2001	21.43	3.73	21.64

Year ended December 31, 2000........................	23.34	3.84	23.29
AVERAGE WELLHEAD PRICE			
Year ended December 31, 2002........................	$23.38	$3.03	$22.42
Year ended December 31, 2001........................	23.25	4.21	23.68
Year ended December 31, 2000........................	28.35	4.58	28.21

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. The hedging policy is set by the President with input from the Chief Executive Officer and the Chief Financial Officer. Trades are executed by the Director of Corporate Planning. The Treasury Department handles the administration functions, which entail tracking existing trades, confirming new trades, and conducting monthly settlements. Our Accounting Department records the transactions in the financial statements. We plan to continue in the normal course of business to hedge our exposure to fluctuating commodity prices. These arrangements will not exceed 75% of anticipated production from proved producing reserves. For the first

six months of 2003, we have approximately 72% of our estimated oil production placed in floors, 45% capped, and 6% in swap agreements and for the last six months of 2003, we have approximately 63% in floors and 47% capped. For the first six months of 2004, we have approximately 27% of our oil production placed in floors and 27% capped and for the last six months of 2004, we have approximately 3% in floors and 3% capped. In addition, for 2003, we have approximately 42% of our estimated natural gas placed in floors, 14% capped, and 14% in swap agreements and for 2004 we have approximately 21% in floors and 11% capped. Our hedging policy does not permit us to engage in hedging transactions for speculation for our own account.

Counterparties. The Company's counterparties to hedging contracts include: Bank of America; BNP Paribas; Deutche Bank; Morgan Stanley; Credit Lyonnais; J. Aron & Company, a wholly-owned subsidiary of Goldman, Sachs & Co.; and CIBC World Markets ("CIBC"), the marketing arm of the Canadian Imperial Bank of Commerce. Approximately 58%, 21%, and 16% of estimated oil production hedged is committed to J. Aron & Company, Morgan Stanley, and Credit Lyonnais, respectively. Approximately 50%, 33%, and 17% of our hedged gas production is contracted with Morgan Stanley, J. Aron & Company, and BNP Paribas, respectively. Performance on all of J. Aron & Company's contracts with the Company is guaranteed by their 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, the Company enters into master netting agreements with significant counterparties. The master netting agreement is a standardized, bilateral contract between the Company and a given counterparty. Instead of treating separately each financial transaction between the Company and its counterparty, the master netting agreement enables the Company and its counterparty 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 the Company. Second, default by a counterparty under one financial trade can trigger rights for the Company to terminate all financial trades with such counterparty. Third, netting of settlement amounts reduces the Company's credit exposure to a given counterparty in the event of close-out.

Commodity price sensitivity. The tables in this section provide information about derivative financial instruments to which we were a party as of December 31, 2002 that are sensitive to changes in oil and natural gas commodity prices.

The Company hedges 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 we 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 statement of operations. At December 31, 2002, we had one such contract in place representing 500 Bbls/D with a strike price of $17.00 per barrel. The unrealized mark-to-market loss on our outstanding commodity derivatives at December 31, 2002 was approximately $8.9 million. The fair market value of our oil hedging contracts was $(4.2) million and the fair market value of our natural gas hedging contracts was $(0.8) million.

OIL HEDGES AT DECEMBER 31, 2002

PERIOD	DAILY FLOOR VOLUME (BBL)	AVERAGE FLOOR PRICE (PER BBL)	DAILY CAP VOLUME (BBL)	AVERAGE CAP PRICE (PER BBL)	DAILY SWAP VOLUME (BBL)	AVERA SWAP P (PER B
Jan. - June 2003.....	12,000	$21.25	7,500	$26.93	1,000	$24.
July - Dec. 2003.....	9,500	21.05	7,000	27.14	--	
Jan. - June 2004.....	4,500	21.00	4,500	27.94	--	
July - Dec. 2004.....	500	21.00	500	26.00	--	

NATURAL GAS HEDGES AT DECEMBER 31, 2002

	DAILY FLOOR VOLUME (MCF)	AVERAGE FLOOR PRICE (PER MCF)	DAILY CAP VOLUME (MCF)	AVERAGE CAP PRICE (PER MCF)	DAILY SWAP VOLUME (MCF)	AVERA SWAP P (PER M
Jan. - Dec. 2003.....	7,500	$3.17	2,500	$6.83	2,500	$3.6
Jan. - Dec. 2004.....	5,000	3.25	5,000	6.10	--	-

Interest rate sensitivity. At December 31, 2002, the Company had total debt of $166.0 million. Of this amount, $150.0 million bears interest at a fixed rate of 8 3/8%. The remaining outstanding debt balance of $16.0 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. We have entered into interest rate swap agreements to hedge the impact of interest rate changes on a portion of our floating rate debt. As of December 31, 2002, we had interest rate swaps as follows:

NOTIONAL SWAP AMOUNT	START DATE	END DATE	ENCORE PAYS	ENCORE RECEIVES	FAIR MA AT DEC 2
(IN THOUSANDS)					(IN TH
$30,000.............	December 19, 2000	March 31, 2005	6.72%	LIBOR	$(
30,000.............	November 19, 2001	November 21, 2005	4.24%	LIBOR	(
80,000.............	June 25, 2002	June 15, 2005	LIBOR + 3.89%	8.375%	

Subsequent to December 31, 2002, the Company cash settled the two outstanding $30 million interest rate swaps at a cost of $4.3 million. Thus, Encore now pays a LIBOR based floating rate on amounts outstanding under our credit facility and on $80 million of swap notional. The following table represents the average three-month forward LIBOR curve by year:

	THREE-MONTH LIBOR AT DECEMBER 31, 2002
2003..	1.36%
2004..	2.30
2005..	3.60

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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:

Acquisition and Development Costs. Capital costs incurred in the acquisition, development, exploitation, and revisions of proved oil and natural gas reserves.

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.

Direct lifting costs. All direct 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.

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.

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.

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 the Company 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. Reserves that are expected to be recovered from new wells on undrilled acreage or from existing wells where a relatively major expenditure is required for recompletion.

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 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.

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

REPORT OF INDEPENDENT AUDITORS

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

We have audited the accompanying consolidated balance sheet of Encore Acquisition Company and subsidiaries as of December 31, 2002, and the related consolidated statements of operations, stockholders' equity, and cash flows for year then ended. 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 audit. The financial statements of Encore Acquisition Company as of December 31, 2001, and for the two-year period then ended were audited by other auditors who have ceased operations. Those auditors expressed an unqualified opinion on those financial statements in their report dated March 1, 2002.

We conducted our audit in accordance with auditing standards generally accepted in the 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 audit provides a reasonable basis for our opinion.

In our opinion, the financial statements referred to above present fairly, in all material respects, the consolidated financial position of Encore Acquisition Company and subsidiaries at December 31, 2002, and the consolidated results of their operations and their cash flows for the year then ended, in conformity with accounting principles generally accepted in the United States.

ERNST & YOUNG LLP

Fort Worth, Texas
January 31, 2003

REPORT OF INDEPENDENT PUBLIC ACCOUNTANTS

To the Shareholders of Encore Acquisition Company:

We have audited the accompanying consolidated balance sheets of Encore Acquisition Company (a Delaware corporation) and subsidiaries as of December 31, 2001 and 2000, and the related consolidated statements of operations, stockholders' equity, and cash flows for each of the three years in the period ended December 31, 2001. 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 auditing standards generally accepted in the 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 financial statements referred to above present fairly, in all material respects, the financial position of Encore Acquisition Company and subsidiaries as of December 31, 2001 and 2000, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2001, in conformity with accounting principles generally accepted in the United States.

As explained in Note 2 to the financial statements, effective January 1, 2001, the Company changed its method of accounting for derivatives.

ARTHUR ANDERSEN LLP

Dallas, Texas
March 1, 2002

Subsequent to the completion of the audit of the Company's 2001 financial statements, Arthur Andersen LLP was convicted of obstruction of justice charges relating to a federal investigation of Enron Corporation and ceased operations as a public accounting firm. Accordingly, the report of independent public accountants included above is a copy of a report previously issued by Arthur Andersen. Arthur Andersen has not reissued its report for inclusion in this document.

ENCORE ACQUISITION COMPANY

CONSOLIDATED BALANCE SHEETS

DECEMBER 31,

	2002	2001
	(IN THOUSANDS EXCEPT SHARE DATA)	
ASSETS		
Current assets:		
Cash and cash equivalents	$ 13,057	$ 115
Accounts receivable (net of allowance of $7.0 million)	21,981	16,286
Deferred tax asset	4,833	--
Derivative assets	3,245	7,030
Other current assets	6,349	5,117
Total current assets	49,465	28,548
Properties and equipment, at cost -- successful efforts method:		
Producing properties	581,012	422,542
Undeveloped properties	1,168	776
Accumulated depletion, depreciation, and amortization	(94,356)	(60,548)
	487,824	362,770
Other property and equipment	3,680	3,001
Accumulated depreciation and amortization	(1,917)	(1,253)
	1,763	1,748
Other assets	10,844	8,934
Total assets	$549,896	$402,000
LIABILITIES AND STOCKHOLDERS' EQUITY		
Current liabilities:		
Accounts payable	$ 9,650	$ 10,793
Derivative liabilities	8,558	3,525
Current portion of note payable	--	1,107
Other current liabilities	18,768	12,016
Total current liabilities	36,976	27,441
Derivative liabilities	2,998	1,288
Long-term debt	166,000	78,000
Deferred income taxes	47,656	25,969
Total liabilities	253,630	132,698
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, 30,162,955 and 30,029,961 issued and outstanding	302	300
Additional paid-in capital	251,231	248,786
Deferred compensation	(2,396)	--
Retained earnings	53,724	16,039
Accumulated other comprehensive income	(6,595)	4,177

Total stockholders' equity	296,266	269,302
Total liabilities and stockholders' equity	$549,896	$402,000

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

ENCORE ACQUISITION COMPANY

CONSOLIDATED STATEMENTS OF OPERATIONS

	YEAR ENDED DECEMBER 31,		
	2002	2001	2000
	(IN THOUSANDS EXCEPT PER SHARE DATA		
Revenues:			
Oil	$134,854	$105,768	$ 92,441
Natural gas	25,838	30,149	16,509
Total revenues	160,692	135,917	108,950
Expenses:			
Production --			
Direct lifting costs	30,678	25,139	18,669
Production, ad valorem, and severance taxes	15,653	13,809	15,159
General and administrative (excluding non-cash stock based compensation)	6,150	5,053	4,345
Non-cash stock based compensation	--	9,587	26,012
Depletion, depreciation, and amortization	34,550	31,721	22,103
Derivative fair value (gain) loss	(900)	680	--
Bad debt expense	--	7,005	--
Impairment of oil and gas properties	--	2,598	--
Other operating expense	1,765	934	--
Total expenses	87,896	96,526	86,288
Operating income	72,796	39,391	22,662
Other income (expenses):			
Interest	(12,306)	(6,041)	(10,490
Other	91	46	512
Total other income (expenses)	(12,215)	(5,995)	(9,978
Income before income taxes	60,581	33,396	12,684
Current income tax benefit (provision)	745	(1,919)	(7,272
Deferred income tax provision	(23,467)	(14,414)	(7,547
Income (loss) before accounting change and extraordinary loss	37,859	17,063	(2,135
Cumulative effect of accounting change, net of tax	--	(884)	--
Extraordinary loss from early extinguishment of debt, net of tax	(174)	--	--
Net income (loss)	$ 37,685	$ 16,179	$ (2,135

Income (loss) per common share before accounting change and extraordinary loss:			
Basic	$ 1.26	$ 0.59	$ (0.09
Diluted	1.26	0.59	(0.09
Income (loss) per common share after accounting change and extraordinary loss:			
Basic	$ 1.25	$ 0.56	$ (0.09
Diluted	1.25	0.56	(0.09
Weighted average common shares outstanding:			
Basic	30,031	28,718	22,806
Diluted	30,161	28,723	22,806

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

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ENCORE ACQUISITION COMPANY

CONSOLIDATED STATEMENT OF STOCKHOLDERS' EQUITY

	CLASS A COMMON STOCK	CLASS B COMMON STOCK	COMMON STOCK	ADDITIONAL PAID-IN CAPITAL	NOTES RECEIVABLE OFFICERS/ EMPLOYEES	TREASU STOCK
	(IN THOUSANDS EXCEPT SHARE DATA)					
BALANCE AT DECEMBER 31, 1999	$ 1	$ 3	$ --	$100,423	$ --	$ --
Issuance of 1,203 shares of A common stock and 49 shares of B common stock and capital call	--	--	--	21,533	--	--
Purchase of 3,177 shares of A common stock and 102 shares of B common stock	--	--	--	--	--	(95
Issuance of 3,177 shares of A common stock held in treasury and 102 shares of B common stock held in treasury	--	--	--	--	--	95
Non-cash stock based compensation	--	--	--	26,012	--	--
Notes receivable -- officers and employees	--	--	--	--	(21)	--
Net income (loss)	--	--	--	--	--	--
BALANCE AT DECEMBER 31, 2000	1	3	--	147,968	(21)	--
Proceeds from initial public offering (net of offering costs of $1,568)	--	--	71	91,456	--	--
Non-cash stock based compensation	--	--	--	9,587	--	--
Recapitalization	(1)	(3)	229	(225)	--	--
Repayment of notes receivable -- officers and employees	--	--	--	--	21	--
Components of comprehensive income:						
Net income	--	--	--	--	--	--
Change in deferred hedge gain/loss (net of income taxes						

of $12,226)..................	--	--	--	--	--	--
Cumulative effect of accounting change (net of income taxes of $9,121)......................	--	--	--	--	--	--
Total comprehensive income........						
BALANCE AT DECEMBER 31, 2001......	--	--	300	248,786	--	--
Exercise of stock options.........	--	--	--	51	--	--
Issuance of restricted stock......	--	--	2	2,394	--	--
Components of comprehensive income:						
Net income......................	--	--	--	--	--	--
Change in deferred hedge gain/loss (Net of income taxes of $6,602)...................	--	--	--	--	--	--
Total comprehensive income........						
BALANCE AT DECEMBER 31, 2002......	$--	$--	$302	$251,231	$ --	$ --

	RETAINED EARNINGS (DEFICIT)	ACCUMULATED OTHER COMPREHENSIVE INCOME	TOTAL STOCKHOLDERS EQUITY
	(IN THOUSANDS EXCEPT SHARE DATA)		
BALANCE AT DECEMBER 31, 1999......	$ 1,995	$ --	$102,422
Issuance of 1,203 shares of A common stock and 49 shares of B common stock and capital call...	--	--	21,533
Purchase of 3,177 shares of A common stock and 102 shares of B common stock..................	--	--	(95)
Issuance of 3,177 shares of A common stock held in treasury and 102 shares of B common stock held in treasury...............	--	--	95
Non-cash stock based compensation...................	--	--	26,012
Notes receivable -- officers and employees......................	--	--	(21)
Net income (loss)................	(2,135)	--	(2,135)
BALANCE AT DECEMBER 31, 2000......	(140)	--	147,811
Proceeds from initial public offering (net of offering costs of $1,568).....................	--	--	91,527
Non-cash stock based compensation...................	--	--	9,587
Recapitalization.................	--	--	--
Repayment of notes receivable -- officers and employees..........	--	--	21
Components of comprehensive income:			
Net income......................	16,179	--	16,179
Change in deferred hedge gain/loss (net of income taxes of $12,226)..................	--	19,058	19,058
Cumulative effect of accounting change (net of income taxes of			

$9,121)	--	(14,881)	(14,881)
Total comprehensive income			20,356
BALANCE AT DECEMBER 31, 2001	16,039	4,177	269,302
Exercise of stock options	--	--	51
Issuance of restricted stock	--	--	--
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	$53,724	$ (6,595)	$296,266

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

ENCORE ACQUISITION COMPANY

CONSOLIDATED STATEMENTS OF CASH FLOWS

	YEAR ENDED DECEMBER 31,		
	2002	2001	2000
	(IN THOUSANDS)		
OPERATING ACTIVITIES			
Net income (loss)	$ 37,685	$ 16,179	$ (2,135)
Adjustments to reconcile net income (loss) to net cash provided by operating activities:			
Depletion, depreciation, and amortization	34,550	31,721	22,103
Deferred taxes	23,361	13,718	7,547
Non-cash stock based compensation	--	9,587	26,012
Non-cash cumulative accounting change	--	884	--
Non-cash derivative fair value (gain) loss	(1,239)	680	--
Extraordinary loss on early extinguishment of debt	174	--	--
Other non-cash charges	3	1,718	88
Loss on disposition of assets	254	165	--
Bad debt expense	--	7,005	--
Impairment of oil and gas properties	--	2,598	--
Changes in operating assets and liabilities:			
Accounts receivable	(5,695)	4,564	(11,315)
Other current assets	(3,161)	(2,258)	(2,797)
Other assets	2,177	(4,605)	(7,449)
Accounts payable and other current liabilities	3,400	(1,744)	12,454
Cash provided by operating activities	91,509	80,212	44,508
INVESTING ACTIVITIES			
Proceeds from disposition of assets	226	310	--
Purchases of other property and equipment	(680)	(1,091)	(606)
Acquisition of oil and gas properties	(78,549)	(1,622)	(70,151)

Development of oil and gas properties	(80,313)	(87,180)	(28,479)
Cash used by investing activities	(159,316)	(89,583)	(99,236)
FINANCING ACTIVITIES			
Proceeds from capital calls	--	--	21,510
Issuance of treasury stock	--	--	95
Repurchase of common stock	--	--	(95)
Proceeds from initial public offering	--	93,095	--
Offering costs paid	--	(1,568)	--
Proceeds from issuance of 8 3/8% notes	150,000	--	--
Payments for debt issuance costs	(6,195)	--	--
Exercise of stock options	51	--	--
Proceeds from notes receivable -- officers and employees	--	21	2
Proceeds from long-term debt	144,000	161,000	118,000
Payments on long-term debt	(206,000)	(227,500)	(72,750)
Payments on note payable	(1,107)	(16,438)	(17,655)
Cash provided by financing activities	80,749	8,610	49,107
INCREASE (DECREASE) IN CASH AND CASH EQUIVALENTS	12,942	(761)	(5,621)
Cash and cash equivalents, beginning of period	115	876	6,497
Cash and cash equivalents, end of period	$ 13,057	$ 115	$ 876
Supplemental disclosure of non-cash investing and financing activities:			
Note payable issued for purchase of oil and gas properties	$ --	$ --	$ 35,200
Notes received from officers and employees in connection with capital calls	$ --	$ --	$ 23

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

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ENCORE ACQUISITION COMPANY

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

1. FORMATION OF THE COMPANY AND BASIS OF PRESENTATION

Encore Acquisition Company (the "Company"), a Delaware Corporation, is an independent (non-integrated) oil and natural gas company in the United States. We were organized in April 1998 and are engaged in the acquisition, development, exploitation, and production of North American oil and natural gas reserves. Our oil and natural gas reserves are concentrated in fields located in the Williston Basin of Montana and North Dakota, the Permian Basin of Texas and New Mexico, the Anadarko Basin of Oklahoma, the Powder River Basin of Montana, and the Paradox Basin of Utah.

2. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

PRINCIPLES OF CONSOLIDATION

Our consolidated financial statements include the accounts of all subsidiaries in which we hold a controlling interest. 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.

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.

OIL AND NATURAL GAS PROPERTIES

We utilize the successful efforts method of accounting for our oil and natural gas properties. Under this method, all development and acquisition costs of proved properties are capitalized and amortized on a unit-of-production basis over the remaining life of proved developed reserves or proved reserves, as applicable. Exploration expenses, including geological and geophysical expenses and delay rentals, are charged to expense as incurred. Costs of drilling exploratory wells are initially capitalized, but charged to expense if and when the well is determined to be unsuccessful. 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. 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. 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 financial statements. Natural gas volumes are converted to equivalent barrels at the rate of six Mcf to one barrel. See "Note 12 -- New Accounting Standards" for a discussion of SFAS 143, "Accounting for Asset Retirement Obligations", which the Company will adopt as of January 1, 2003.

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 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. Any impairment charge incurred is expensed and recorded in accumulated depletion, depreciation, and amortization ("DD&A") to reduce our recorded basis in the asset.

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 and the subsequent three quarters of the new year.

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. If compensation expense for the stock based awards had been determined using the provisions of 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, 2002	YEAR ENDED DECEMBER 31, 2001	YEAR ENDED DECEMBER 31, 2000
As Reported:			
Net income (loss)............................	$37,685	$16,179	$(2,135)
Diluted net income (loss) per share...........	1.25	0.56	(0.09)
Non-cash stock based compensation.............	--	9,587	26,012
Pro Forma:			
Net income (loss)............................	$36,408	$15,475	$(2,135)
Diluted net income (loss) per share...........	1.21	0.54	(0.09)
Non-cash stock based compensation.............	1,277	10,291	26,012

SEGMENT REPORTING

The Company operates in 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 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. For 2001, 25%, 17%, and 11% of total oil and natural gas sales were to ConAgra, Equiva Trading Company and EOTT Energy Co., respectively. For 2000, our largest purchasers included Equiva Trading Company and EOTT Energy Co, which accounted for 56% and 11% 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 from jointly owned properties as oil and natural gas is produced and sold, net of royalties. Revenues from natural gas production are recorded using the sales method, net of royalties. Under this method, revenue is recognized based on the cash received rather than our proportionate share of natural gas produced. Natural gas imbalances under-delivered to Encore at December 31, 2002 and December 31, 2001, were 510,000 MMbtu and 483,000 MMbtu, respectively. Revenues are stated net of any net profits interests held by others. The reduction in revenue from net profits interest totaled $2.0 million, $2.8 million, and $11.5 million in 2002, 2001, and 2000, respectively.

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 statement 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 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 with large financial institutions.

Prior to January 1, 2001, these agreements were accounted for as hedges using the deferral method of accounting. Unrealized gains and losses were generally not recognized until the physical production required by the contracts was delivered. At the time of delivery, the resulting gains and losses were recognized as an adjustment to oil and natural gas revenues. The cash flows related to any recognized gains or losses associated with these hedges were reported as cash flows from operations. If the hedge was terminated prior to maturity, gains or losses were deferred and included in income in the same period as the physical production required by the contracts was delivered.

We also use derivative instruments in the form of interest rate swaps, which hedge our risk related to interest rate fluctuation. Prior to January 1, 2001, these agreements were accounted for as hedges using the accrual method of accounting. The differences to be paid or received on swaps designated as hedges were included in interest expense during the period to which the payment or receipt related. The cash flows related to recognized gains or losses associated with these hedges were reported as cash flows from operations.

Effective January 1, 2001, the Company adopted Statement of Financial Accounting Standards No. 133 ("SFAS 133"), "Accounting for Derivative Instruments and Hedging Activities". This standard requires us to recognize all of our derivative and hedging 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 due to changes in the underlying item being hedged. In

addition, all hedging relationships must be designated, documented, and reassessed periodically. The impact of adopting SFAS 133 on January 1, 2001 was to record the fair value of our derivatives as a reduction in assets of $1.1 million and as a liability in the amount of $24.4 million. Additionally, we recorded a reduction in earnings as the cumulative effect of an accounting change of $0.9 million (net of taxes of $0.5 million) and a decrease to stockholders' equity for other comprehensive income in the amount of $14.9 million (net of taxes of $9.1 million).

Currently, all of our derivative financial instruments that qualify for hedge accounting 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 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 into earnings immediately.

USE OF ESTIMATES

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

Estimates with regard to these financial statements include the estimate of proved oil and natural gas reserve volumes and the estimated future development, dismantlement, and abandonment costs used in determining amortization provisions. In addition, significant estimates are required for our assessment of impairment of long-lived assets. Future changes in the assumptions used could have a significant impact on whether impairment provisions are required in future periods.

COMPREHENSIVE INCOME

Comprehensive income includes net income and other comprehensive income, which includes, but is not limited to, unrealized gains and losses on marketable securities, foreign currency translation adjustments, minimum pension liability adjustments, and effective January 1, 2001, unrealized gains and losses on derivative financial instruments. Encore chooses to show yearly comprehensive income as part of its consolidated statement of stockholders' equity.

With the adoption of SFAS 133 on January 1, 2001, the Company began recording deferred hedge gains and losses on our derivative financial instruments as other comprehensive income. For the year ended December 31, 2001, comprehensive income totaled $20.4 million, while net income totaled $16.2 million. The difference between net income and comprehensive income is the result of recording a $14.9 million deferred hedge loss as a cumulative change in accounting, as well as a $19.1 million deferred hedge gain for the year ended December 31, 2001. The deferred hedge gain for 2001 resulted from a reduction in the market price of oil and natural gas during the year. The company had $4.2 million at December 31, 2001, in deferred hedge gains, net of tax, in accumulated other comprehensive income, shown as a component of equity on the balance sheet.

For the year ended December 31, 2002, comprehensive income totaled $26.9 million, while net income totaled $37.7 million. The difference between net income and comprehensive income is the result of recording a $10.8 million deferred hedge loss. The deferred hedge loss for 2002 resulted from an increase in the market price of oil and natural gas during the year. The company had $6.6 million at December 31, 2002 in deferred hedge losses, net of tax, in accumulated other comprehensive income, shown as a component of equity on the balance sheet.

NEW ACCOUNTING STANDARDS

In August 2001, the FASB issued Statement of Financial Accounting Standards No. 143 ("SFAS 143"), Accounting for Asset Retirement Obligations, which the Company will be required to adopt 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 adjustment to record (i) a $4.0 million increase in the carrying values of proved properties, (ii) a $2.1 million decrease in accumulated depletion, depreciation, and amortization, and (iii) a $5.2 million increase in other non-current liabilities, and (iv) a gain of $0.9 million, net of tax, as a cumulative effect of accounting change on January 1, 2003.

In April 2002, the FASB issued SFAS 145, "Rescission of FASB Statements No. 4, 44, and 64, Amendment of FASB Statement No. 13, and Technical Corrections". Under Statement 4, all gains and losses from extinguishment of debt were required to be aggregated and, if material, classified as an extraordinary item, net of related income tax effect. This Statement eliminates Statement 4 and, thus, the exception to applying Opinion 30 to all gains and losses related to extinguishments of debt. As a result, gains and losses from extinguishment of debt should be classified as extraordinary items only if they meet the criteria in Opinion 30. Applying the provisions of Opinion 30 will distinguish transactions that are part of an entity's recurring operations from those that are unusual or infrequent or that meet the criteria for classification as an extraordinary item. This statement is effective for Encore beginning January 1, 2003, at which time the extraordinary loss on extinguishment of debt recorded in the second quarter of 2002 will be reclassified to operating income.

3. OIL AND NATURAL GAS PROPERTIES

The cost of oil and natural gas properties at December 31, 2002 includes $1.2 million of undeveloped leasehold costs. Such properties are held for development or resale. The following table sets forth costs incurred related to oil and natural gas properties:

	2002	2001	2000
	(IN THOUSANDS)		
Proved property acquisition costs	$ 78,158	$ 1,471	$104,727
Undeveloped leasehold acquisition costs	391	151	624
Development costs	80,313	87,180	28,479
Total	$158,862	$88,802	$133,830

2000 ACQUISITIONS

On February 23, 2000, the Company executed a purchase and sale agreement to acquire working interests in 278 wells located in Crockett County, Texas (approximately 130 wells operated, 148 non-operated) for $43 million. The transaction closed on March 30, 2000.

On March 6, 2000, the Company executed a purchase and sale agreement to acquire working interests in 25 wells, (23 non-operated, two operated) located in Stark County, North Dakota for $35.2 million. The transaction closed on March 31, 2000.

The Company executed a purchase and sale agreement to acquire working interests in 161 wells located in Oklahoma and New Mexico (approximately seven wells operated, 154 non-operated) for $25.4 million. The transaction closed on August 24, 2000 with an effective date of April 1, 2000.

2001 ACQUISITIONS

During 2001, we made small miscellaneous acquisitions of undeveloped acreage. No material proved property acquisitions were made.

2002 ACQUISITIONS

On January 4, 2002 we closed the purchase of our sixth major producing property package since inception. These Central Permian 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 Chevron Texaco.

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.

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 our remaining non-cancelable future payments under operating leases as of December 31, 2002 (in thousands):

2003	$959
2004	951
2005	987
2006	520
2007	171
Thereafter	213

Our operating lease rental expense was approximately $0.9 million, $0.7 million, and $0.3 million in 2002, 2001, and 2000, respectively.

5. ACCOUNTS PAYABLE AND ACCRUED LIABILITIES

Accounts payable and accrued liabilities were as follows at December 31 (in thousands):

	2002	2001
Accounts payable trade	$ 9,650	$10,793
Oil and natural gas revenue payable	4,108	3,284
Property and production taxes	4,822	2,581
Net proceeds payable	237	80
Interest	595	1,451
Direct lifting costs	2,373	2,097
Drilling costs	4,500	1,100
Other	2,133	1,423
Total	$28,418	$22,809

6. INDEBTEDNESS

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

	2002	2001

Credit Agreement	$ 16,000	$78,000
8 3/8% Notes	150,000	--
Note payable	--	1,107
Total	166,000	79,107
Less: Current portion of note payable	--	1,107
Long-term debt, net of current portion	$166,000	$78,000

Prior to restructuring our debt on June 25, 2002 (see below), the Company's operating subsidiary maintained a credit agreement with a group of banks that matured in May 2004. The Company guaranteed the subsidiary's obligations under the credit agreement and pledged the stock and other equity interests of its subsidiaries to secure the guaranty. Borrowings under the credit agreement totaled $78.0 million as of December 31, 2001. The borrowing base, as established in the credit agreement, was $180.0 million as of December 31, 2001. During 2001 and 2000, the weighted average interest rate under the facility was 5.7% and 7.8%, respectively.

In 2001, the Company issued a $35.2 million note payable to the seller in connection with the Lodgepole acquisition in North Dakota. The note bore monthly compounded interest at the rate of 4% per annum on the outstanding principal plus accrued interest. The remaining amount payable at December 31, 2001 was $1.1 million, which along with accrued interest of $1.3 million, was paid in January 2002.

On June 25, 2002, the Company sold $150 million of 8 3/8% Senior Subordinated Notes maturing on June 15, 2012 (the "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 Notes, after deducting debt issuance costs. The proceeds were used to repay and retire the Company's prior credit facility ($143.0 million), to pay the fees and expenses related to the new credit facility ($1.5 million), and to hold in reserve for the Paradox Basin acquisition ($1.1 million).

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

Concurrently with the issuance of the Notes, the Company also entered into a new Revolving Credit Facility on June 25, 2002. Borrowings under the facility are secured by a first priority lien on the Company's proved oil and natural gas reserves. Availability under the facility is determined through semi-annual borrowing base determinations and may be increased or decreased. The amount available under the new facility is $220.0 million, with $16.0 million outstanding as of December 31, 2002. The maturity date of the new facility is June 25, 2006.

Amounts outstanding under the facility are subject to varying rates of interest based on the amount outstanding and the Company's borrowing base. Based on our current $220.0 million borrowing base, our applicable interest rates are calculated as follows:

AMOUNT OUTSTANDING	RATE
$0 to $55,000,000	LIBOR + 1.000%
$55,000,001 to $110,000,000	LIBOR + 1.125%
$110,000,001 to $165,000,000	LIBOR + 1.250%
$165,000,001 to $198,000,000	LIBOR + 1.500%
$198,000,001 to $220,000,000	LIBOR + 1.750%

Additionally, under the new Revolving Credit Facility, the Company is subject to certain affirmative, negative, and financial covenants. These 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 an EBITDA, as defined, to interest expense ratio of at least 2.5 to 1.0. As of December 31, 2002, the Company was in compliance with all covenants.

The following table illustrates the Company's long-term debt maturities at December 31, 2002 (in thousands):

	PAYMENTS DUE BY PERIOD				
CONTRACTUAL OBLIGATIONS	TOTAL	2003	2004-2005	2006-2007	THEREAFTER
8 3/8% Notes	$150,000	$ --	$ --	$ --	$150,000
Revolving Credit Facility	16,000	--	--	16,000	--
Totals	$166,000	$ --	$ --	$16,000	$150,000

Consolidated cash payments for interest were $13.2 million, $6.4 million, and $10.2 million, respectively, for 2002, 2001, and 2000.

7. 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 statement of operations were attributed to the following items (in thousands):

	DECEMBER 31, 2002	2001	2000
Taxes related to:			
Income/loss before cumulative effect of accounting change and extraordinary item	$22,722	$16,333	$14,819
Cumulative effect of accounting change	--	541	--
Extraordinary item	107	--	--
Total tax expense	$22,829	$16,874	$14,819

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):

	DECEMBER 31, 2002	2001	2000
Federal:			
Current	$ (745)	$ 1,919	$ 6,292
Deferred	21,658	13,125	7,547
Total federal	20,913	15,044	13,839
State:			
Current	--	--	980
Deferred	1,809	1,289	--
Total state	1,809	1,289	980
Income tax provision	$22,722	$16,333	$14,819

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

	DECEMBER 31, 2002	2001	2000
Income before income taxes	$60,581	$33,396	$12,684
Tax at statutory rate	$21,203	$11,689	$ 4,439
State income taxes, net of federal benefit	1,809	1,289	980
Non-cash stock based compensation	--	3,355	9,104
Section 43 credits	(632)	--	--
Other	342	--	296
Income tax expense	$22,722	$16,333	$14,819

ENCORE ACQUISITION COMPANY

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS -- (CONTINUED)

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):

	2002	2001
CURRENT:		
Assets:		
Allowance for bad debt	$ 984	$ 2,662
Derivative fair value loss	--	258
Unrealized hedge loss in other comprehensive income	3,883	--
Other	65	--
Total current deferred tax assets	4,932	2,920
Liabilities:		
Derivative fair value loss	(99)	(2,899)
Net current deferred tax asset	$ 4,833	$ 21
LONG-TERM:		
Assets:		
Alternative minimum tax	$ 1,312	$ 1,919
Net operating loss carryforwards	--	4,298
Unrealized hedge loss in other comprehensive income	159	339
Section 43 credits	1,019	--
Other	14	92
Total long-term deferred tax assets	2,504	6,648
Liabilities:		
Book basis of oil and natural gas properties in excess of tax basis	(50,160)	(32,617)
Net long-term deferred tax liability	$(47,656)	$(25,969)

No cash income tax payments were made in 2002. Cash income tax payments in the amount of $1.5 million and $4.0 million were made in 2001 and 2000, respectively.

TAXES OTHER THAN INCOME TAXES

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

	DECEMBER 31,		
	2002	2001	2000

Production and severance	$14,397	$13,303	$14,616
Property and ad valorem	1,256	506	543
Payroll and other	383	316	210
Total	$16,036	$14,125	$15,369

8. STOCKHOLDERS' EQUITY

COMMON STOCK

On August 18, 1998, the Company entered into a Stock Purchase Agreement and a Stockholders' Agreement (collectively the "Agreements"), with members of our management ("Management") and

non-management investors (the "Investors"). Under the terms of the Agreements, 294,901 shares of Class B Common Stock, par value $0.01 per share (the "Class B") and 73,725 shares of Class A Common Stock, par value $0.01 per share ("Class A") were authorized to be issued for a total amount of committed consideration to be invested in the Company of $298 million by Management and the Investors.

At December 31, 2000, 294,901 shares of Class B and 73,725 shares of Class A were issued and outstanding. The total Management capital commitment for Class A and Class B shares was approximately $8 million.

During 2000, an additional 4,380 shares of Class A common stock were sold to employees of the Company.

During 2000, capital calls totaling $21.5 million were initiated in order to fund the acquisitions of oil and natural gas properties.

On March 8, 2001, the Company priced its shares to be issued in its initial public offering ("IPO") and began trading on the New York Stock Exchange the following day under the ticker symbol "EAC". Immediately prior to Encore's IPO, all of the outstanding shares of Class A and Class B stock held by management and institutional investors were converted into 2,630,203 and 20,249,758 shares, respectively, of a single class of common stock. Through the IPO, the Company sold an additional 7,150,000 shares of common stock to the public at the offering price of $14.00 per share, resulting in total outstanding shares of 30,029,961. The Company received $91.5 million in net proceeds after deducting the underwriter's discounts and commissions and related offering expenses. The proceeds received from the IPO were used to pay down debt outstanding under our credit facility.

PREFERRED STOCK

The Company has authorized a class of undesignated preferred stock consisting of 5,000,000 shares, 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.

NON-CASH STOCK BASED COMPENSATION EXPENSE ON CLASS A STOCK

The Company followed variable plan accounting for the Class A stock sold to management. Accordingly, compensation expense was based on the excess of the estimated fair value of the Class A stock over the amount paid by the shareholders. Compensation expense was adjusted in each reporting period based on the most recent fair value estimates until the measurement date occurred. Compensation expense was recorded over the expected service period of the Class A stock, which was based on a vesting schedule. The Class A stock vested 25% upon issuance and an additional 15% per year for the following five years. Prior to September 1, 2000, the Company estimated the fair value of our Class A common stock based on discounted cash flow estimates of our oil and gas properties. Beginning on September 1, 2000, we estimated the fair value of the Class A stock based on 90% of the estimated offering price in the Company's IPO. The measurement date occurred on March 8, 2001, the date of the IPO, as after this date the Class A shareholders were no longer required to make future capital contributions. Total compensation expense on the Class A shares using the IPO price of $14.00 per share was $35.6 million. Based on the estimated fair values and vesting at the end of each period, the Company recorded $9.6 million of compensation expense for 2001 and $26.0 million in 2000. The $9.6 million recorded in the first quarter of 2001 represented the final compensation expense to be recorded related to the Class A shares.

9. EARNINGS (LOSS) 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,		
	2002	2001	2000
NUMERATOR:			
Income (loss) before accounting change and extraordinary item	$37,859	$17,063	$(2,135)
Net income (loss)	$37,685	$16,179	$(2,135)
DENOMINATOR:			
Denominator for basic earnings per share -- weighted average shares outstanding	30,031	28,718	22,806
Effect of dilutive securities:			
Dilutive options(a)	130	5	--
Denominator for diluted earnings per share	30,161	28,723	22,806
Basic income (loss) per common share before accounting change and extraordinary item	$ 1.26	$ 0.59	$ (0.09)
Cumulative effect of accounting change and extraordinary item, net of tax	(0.01)	(0.03)	--

Basic income (loss) per common share after accounting change and extraordinary item	$ 1.25	$ 0.56	$ (0.09)
Diluted income (loss) per common share before accounting change and extraordinary item	$ 1.26	$ 0.59	$ (0.09)
Cumulative effect of accounting change and extraordinary item, net of tax	(0.01)	(0.03)	--
Diluted income (loss) per common share after accounting change and extraordinary item	$ 1.25	$ 0.56	$ (0.09)

(a) Options to purchase 272,177 shares of common stock were outstanding but not included in calculation of 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 above amounts.

10. 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 employee contributions, totaled $0.5 million in 2002, $0.4 million in 2001, and $0.3 million in 2000. 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 approved the 2000 Incentive Stock Plan. 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 reserved and available for distribution pursuant to the plan is 1.8 million shares. The plan provides for the granting of incentive stock options, non-qualified stock options, and restricted stock at the discretion of the Company's Board of Directors.

All options 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 number of options and their related weighted average strike prices for 2002 and 2001:

	FOR THE YEAR ENDED DECEMBER 31, 2002	FOR THE YEAR ENDED DECEMBER 31, 2001

	NUMBER OF OPTIONS	WEIGHTED AVERAGE STRIKE PRICE	NUMBER OF OPTIONS	WEIGHTED AVERAGE STRIKE PRICE
Outstanding at Beginning of Year	847,500	$13.44	--	$ --
Granted(a)	378,177	17.21	940,000	13.49
Forfeited	(43,500)	14.24	(92,500)	14.00
Exercised	(3,666)	14.00	--	--
Outstanding at End of Year(b)	1,178,511	14.62	847,500	13.44
Exercisable at End of Year	324,278	13.31	--	--

(a) None and 4,000 of the options granted in 2002 and 2001, respectively, were granted to non-employee directors. The weighted average fair value of individual options granted in 2002 and 2001 was $6.91 and $4.02, respectively.

(b) The options outstanding at December 31, 2001 had strike prices ranging from $12.49 to $14.00 and had a weighted average remaining life of 9.4 years. At December 31, 2002, there were 886,334 options outstanding with strike prices between $12.49 and $14.00. These had a weighted average remaining life of 8.5 years and a weighted average strike price of $13.38. Additionally, at December 31, 2002, there were 292,177 options with strike prices between $14.01 and $18.60. These had a weighted average remaining life of 9.9 years and a weighted average strike price of $18.36.

The restricted stock granted under the plan vests equally in years three, four, and five after issuance. During 2002 and 2001, 129,328 and zero shares, respectively, of restricted stock was issued to employees. Of the 129,328 issued at the end of 2002, 77,597 shares 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. The remaining 51,731 shares were issued to four members of senior management. These shares not only depend on the passage of time, 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. The stock price on the date of grant in 2002 was $18.60.

SFAS 123 DISCLOSURES

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. See "Stock-based Compensation" in Note 2. The following amounts represent weighted average values used in the model to calculate the fair value of the options granted during 2002 and 2001:

	YEAR ENDED DECEMBER 31, 2002	YEAR ENDED DECEMBER 31, 2001
Risk free interest rate	3.4%	4.4%
Expected life	4 years	4 years
Expected volatility	46.7%	28.9%
Expected dividend yield	0.0%	0.0%

11. FINANCIAL INSTRUMENTS

The following table sets forth the book value and estimated fair value of financial instruments (in thousands):

	DECEMBER 31, 2002		DECEMBER 31, 2001	
	BOOK VALUE	FAIR VALUE	BOOK VALUE	FAIR VALUE
Cash and cash equivalents	$ 13,057	$ 13,057	$ 115	$ 115
Long-term debt	(166,000)	(172,000)	(78,000)	(78,000)
Long-term commodity contracts	(5,047)	(5,047)	7,463	7,463
Interest rate swaps	(1,325)	(1,325)	(1,813)	(1,813)
Note payable	--	--	(1,107)	(1,107)

The book value of cash and cash equivalents approximates fair value because of the short maturity of these instruments. Since the note payable was payable on demand if called by the issuer, fair value approximated book 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 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 statement of operations. At December 31, 2002, we had one such contract in place representing 500 Bbls/D with a strike price of $17.00 per barrel.

The following tables summarize our open commodity hedging positions as of December 31, 2002:

OIL HEDGES AT DECEMBER 31, 2002

PERIOD	DAILY FLOOR VOLUME (BBL)	FLOOR PRICE (PER BBL)	DAILY CAP VOLUME (BBL)	CAP PRICE (PER BBL)	DAILY SWAP VOLUME (BBL)	SWAP PRICE (PER BBL
Jan. - June 2003.....	12,000	$21.25	7,500	$26.93	1,000	$24.50
July - Dec. 2003.....	9,500	21.05	7,000	27.14	--	--
Jan. - June 2004.....	4,500	21.00	4,500	27.94	--	--
July - Dec. 2004.....	500	21.00	500	26.00	--	--

NATURAL GAS HEDGES AT DECEMBER 31, 2002

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
2003................	7,500	$3.17	2,500	$6.83	2,500	$3.69
2004................	5,000	3.25	5,000	6.10	--	--

As a result of all of our hedging transactions for oil and natural gas we recognized a pre-tax reduction in earnings of approximately $5.2 million, $12.8 million, and $23.0 million in 2002, 2001, and 2000, respectively. Based on the fair value of our hedges at December 31, 2002, our unrealized pre-tax loss recorded in other comprehensive income related to outstanding hedges is $7.3 million for oil and $1.6 million for natural gas. These amounts will be reclassified to earnings as the related production affects earnings during 2003 and 2004. Of the total deferred hedge loss related to commodity contracts, $8.7 million relates to 2003 contracts and $0.2 million relates to 2004 contracts. The actual gains or losses we realize from our commodity hedge transactions may vary significantly from these amounts due to the fluctuation of prices in the commodity markets. In order to calculate the unrealized gain or loss, the relevant variables are (1) the type of commodity, (2) the delivery price, and (3) the delivery location. These calculations may be used to analyze the gains and losses we might realize on our financial hedging contracts and do not reflect the effects of price changes on our actual physical commodity sales.

INTEREST RATE DERIVATIVES

As discussed in Note 6, in conjunction with the sale of the Notes, the Company repaid all amounts outstanding under its previous credit facility on June 25, 2002, and terminated the 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. The unrealized loss of $3.8 million through June 25, 2002, which was recognized in accumulated other comprehensive income, 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)

During the third quarter of 2002, the Company cash settled one of the three interest rate swaps discussed above, resulting in an additional loss of $0.4 million, which was recognized as "Derivative fair value gain/loss" in the statement of operations.

Also, in conjunction with the sale of the Notes (See Note 6), the Company entered into an additional interest rate swap, whereby we pay a six-month trailing LIBOR rate plus 3.89% and receive a fixed 8 3/8% on a notional of $80 million through June 15, 2005. Due to the difference in terms between the swap and the underlying debt, this instrument does not qualify for hedge accounting and, along with future changes in the fair value of the two remaining swaps discussed above, will be marked to market through earnings each period as "Derivative fair value gain/loss," in the statement of operations.

As of December 31, 2002, we had interest swaps as follows:

NOTIONAL SWAP AMOUNT (IN THOUSANDS)	START DATE	END DATE	ENCORE PAYS	ENCORE RECEIVES	FAIR MARKET VAL AT DECEMBER 31 2002 (IN THOUSANDS)
$30,000.......	December 19, 2000	March 31, 2005	6.72%	LIBOR	$(3,189)
$30,000.......	November 19, 2001	November 21, 2005	4.24%	LIBOR	$(1,734)
$80,000.......	June 25, 2002	June 15, 2005	LIBOR + 3.89%	8.375%	$ 3,597

As a result of our hedging transactions for interest, we recognized in interest expense a pre-tax loss of approximately $1.6 million, $0.7 million, and $0.1 million in 2002, 2001, and 2000, respectively. Additionally, $0.2 million was recognized in "Derivative fair value gain/loss" in 2002 as our interest rate swaps do not qualify for hedge accounting after June 25, 2002. The actual gains or losses we realize from our interest rate swaps may vary significantly from these amounts due to fluctuations in the LIBOR interest rate.

COUNTERPARTY RISK

The Company's counterparties to hedging contracts include: Bank of America; BNP Paribas; Deutche Bank; Morgan Stanley; Credit Lyonnais; J. Aron & Company, a wholly-owned subsidiary of Goldman, Sachs & Co.; and CIBC World Markets ("CIBC"), the marketing arm of the Canadian Imperial Bank of Commerce. Approximately 58%, 21%, and 16% of estimated oil production hedged is committed to J. Aron & Company, Morgan Stanley, and Credit Lyonnais, respectively. Approximately 50%, 33%, and 17% of our hedged gas production is contracted with Morgan Stanley, J. Aron & Company, and BNP Paribas, respectively. Performance on all of J. Aron & Company's contracts with the Company is guaranteed by their 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. However, 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 the Company and a given counterparty. Instead of treating each financial transaction between the Company and its counterparty separately, the master netting agreement enables the Company and its counterparty 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 the Company. Second, default by a counterparty under one financial trade can trigger rights for the Company to terminate all financial trades with such counterparty. Third, netting of settlement amounts reduces the Company's credit exposure to a given counterparty in the event of close-out.

12. 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 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 us by Enron, for the year ended December 31, 2001, we have recorded a charge to bad debt expense for the full amount of the receivable, $7.0 million, and recorded a related allowance on the receivable of $7.0 million. Any ultimate recovery on the Enron receivable will be recognized in earnings when management believes recovery of the asset to be probable.

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. According to the provisions of SFAS 133, this gain must be recorded in other comprehensive income until such time as the original hedged production affects income. As a result, at December 31, 2001, the Company had $4.8 million in gross unrecognized gains in other comprehensive income that will be reversed into earnings during 2002 and 2003. The following table illustrates the current and future amortization of this amount to revenue (in thousands):

PERIOD	OIL	GAS	TOTAL
2002	$2,822	$1,594	$4,416
2003	401	18	419
Total	$3,223	$1,612	$4,835

13. IMPAIRMENT OF LONG-LIVED ASSETS

Throughout 2001, futures prices for oil and natural gas continued to decline from their December 31, 2000 levels. The SEC price case used for our 2000 reserve estimate was $26.80 per Bbl and $9.77 per Mcf dropping to $19.84 per Bbl and $2.57 per Mcf for the 2001 estimate. Although the SEC price case does not necessarily coincide with management's estimates of future prices, this indicated the need to assess our oil and natural gas properties for any possible impairment. Thus, we compared the undiscounted future cash flows for each of our oil and natural gas properties to their net book value, which indicated the need for an impairment charge on certain properties. We then compared the net book value of the impaired assets to their estimated fair value, which resulted in a write-down of the value of proved oil and gas properties of $2.6 million. Fair value was determined using estimates of future production volumes and estimates of future prices we might receive for these volumes discounted back to a present value using a rate commensurate with the risks inherent in the industry. We performed a similar review at December 31, 2000 and 2002, and determined no impairment charge was necessary.

14. SUBSEQUENT EVENTS

During January 2003, the Company cash settled the two outstanding $30 million interest rate swaps at a cost of $4.3 million. Thus, Encore now pays a LIBOR based floating rate on amounts outstanding under our credit facility and on $80 million of swap notional.

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UNAUDITED SUPPLEMENTAL INFORMATION

OIL & NATURAL GAS PRODUCING ACTIVITIES

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 indicated 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 the 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, 2002, 2001, and, 2000 were $31.20, $19.84, and $26.80 per barrel for oil and $4.79, $2.57, and $9.77 per Mcf for natural gas respectively. The net profits interest on our Cedar Creek Anticline properties has been deducted from future cash inflows in the calculation of Standardized Measure. The Company's reserve and production quantities 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 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 shown below. 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 depreciation, depletion, and amortization on these properties.

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

	OIL (MBBL)	NATURAL GAS (MMCF)	OIL EQUIVALENT (MBOE)
December 31, 2002			
Proved reserves	111,674	99,818	128,310
Proved developed reserves	93,945	82,217	107,648
December 31, 2001			
Proved reserves	91,369	75,687	103,983
Proved developed reserves	71,639	69,941	83,296
December 31, 2000			
Proved reserves	78,910	72,970	91,072
Proved developed reserves	66,363	66,337	77,419

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

	OIL (MBBL)	NATURAL GAS (MMCF)	OIL EQUIVALENT (MBOE)
Balance, December 31, 1999	69,299	10,940	71,122
Acquisitions of minerals-in-place	4,162	63,136	14,685
Extensions and discoveries	8,237	1,733	8,526

Revisions of estimates	1,173	1,464	1,417
Production	(3,961)	(4,303)	(4,678)
Balance, December 31, 2000	78,910	72,970	91,072
Acquisitions of minerals-in-place	--	--	--
Extensions and discoveries	19,266	14,063	21,610
Revisions of estimates	(1,872)	(3,268)	(2,418)
Production	(4,935)	(8,078)	(6,281)
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

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 at:

	DECEMBER 31,		
	2002	2001	2000
Net future cash inflows	$ 3,648,515	$1,770,384	$2,611,633
Future production costs	(1,448,110)	(794,139)	(998,660)
Future development costs	(63,194)	(67,652)	(45,583)
Future income tax expense	(623,987)	(215,568)	(377,789)
Future net cash flows	1,513,224	693,025	1,189,601
10% annual discount	(888,506)	(408,716)	(590,325)
Standardized measure of discounted estimated future net cash flows	$ 624,718	$ 284,309	$ 599,276

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

	YEAR ENDED DECEMBER 31,		
	2002	2001	2000
Standardized measure, beginning of year	$ 284,309	$ 599,276	$272,955
Net change in sales price, net of production costs	305,097	(334,809)	19,764
Extensions and discoveries	135,897	71,090	75,236

Development costs incurred during the year	80,313	87,179	26,508
Revisions of quantity estimates	18,216	(18,244)	9,822
Accretion of discount	36,036	70,636	32,325
Change in future development costs	(44,285)	(51,238)	(18,667)
Acquisitions of minerals-in-place	131,370	--	336,601
Sales, net of production costs	(114,361)	(96,969)	(75,122)
Change in timing and other	(43,540)	(73,640)	(23,362)
Net change in income taxes	(164,334)	31,028	(56,784)
Standardized measure, end of year	$ 624,718	$ 284,309	$599,276

SELECTED QUARTERLY FINANCIAL DATA

The following table sets forth selected quarterly financial data for the years ended December 31, 2002 and 2001:

	QUARTER			
	FIRST	SECOND	THIRD	FOURTH
	(IN THOUSANDS, EXCEPT PER SHARE DATA)			
2002				
Revenues	$32,297	$37,807	$43,502	$47,086
Operating income	$12,929	$17,232	$19,789	$22,846
Income before extraordinary loss	$ 7,110	$ 9,300	$10,113	$11,336
Extraordinary loss, net of tax	--	(174)	--	--
Net income	$ 7,110	$ 9,126	$10,113	$11,336
Basic income per common share:				
Before extraordinary loss	$ 0.24	$ 0.31	$ 0.34	$ 0.38
Extraordinary loss, net of tax	--	(0.01)	--	--
After extraordinary loss	$ 0.24	$ 0.30	$ 0.34	$ 0.38
Diluted income per common share:				
Before extraordinary loss	$ 0.24	$ 0.31	$ 0.33	$ 0.38
Extraordinary loss, net of tax	--	(0.01)	--	--
After extraordinary loss	$ 0.24	$ 0.30	$ 0.33	$ 0.38
2001				
Revenues	$36,221	$34,608	$34,539	$30,549
Operating Income	$ 7,081	$15,781	$14,655	$ 1,874
Income (loss) before accounting change	$ (793)	$ 9,061	$ 8,423	$ 372
Cumulative effect of accounting change, net of tax	(884)	--	--	--
Net income (loss)	$(1,677)	$ 9,061	$ 8,423	$ 372
Basic income (loss) per common share:				
Before accounting change	$ (0.03)	$ 0.30	$ 0.28	$ 0.01
Cumulative effect of accounting change, net of tax	(0.04)	--	--	--

After accounting change	$ (0.07)	$ 0.30	$ 0.28	$ 0.01
Diluted income (loss) per common share:				
Before accounting change	$ (0.03)	$ 0.30	$ 0.28	$ 0.01
Cumulative effect of accounting change, net of tax	(0.04)	--	--	--
After accounting change	$ (0.07)	$ 0.30	$ 0.28	$ 0.01

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

On April 1, 2002, we dismissed Arthur Andersen LLP as our independent accountants effective as of that date. The decision to dismiss Arthur Andersen LLP was recommended by the Audit Committee of the Board of Directors and was approved by the Board of Directors on April 1, 2002.

Arthur Andersen's report on the Company's financial statements for the fiscal year ended December 31, 2001 did not contain an adverse opinion or disclaimer of opinion and was not qualified or modified as to uncertainty or audit scope. Arthur Andersen LLP included in its opinion explanatory language related to the Company's change in its method of accounting for derivatives as a result of the Company's adoption of Statement of Financial Accounting Standards No. 133, "Accounting for Derivative Instruments and Hedging Activities." During 2001 and the period from January 1, 2002 through the date of Arthur Andersen LLP's termination, there were no disagreements between us and Arthur Andersen LLP on any matter of accounting principles or practices, financial statement disclosure, or auditing scope or procedure, that, if not resolved to the satisfaction of Arthur Andersen LLP, pursuant to Item 304(a)(1) of Regulation S-K, would have caused it to make reference to the subject matter of the disagreements in its report.

As required under the regulations of the SEC, we provided Arthur Andersen LLP with a copy of our disclosure in connection with this matter and requested Arthur Andersen LLP to furnish us with a letter addressed to the SEC stating whether it agreed with our statements and, if not, stating the respects in which it did not agree. Arthur Andersen LLP's letter was filed as Exhibit 16.1 to our Current Report on Form 8-K filed with the SEC on April 5, 2002.

Effective April 11, 2002, we engaged Ernst & Young LLP, as our new independent accountants for the fiscal year ending December 31, 2002. The decision to appoint Ernst & Young LLP was recommended by the Audit Committee of the Board of Directors and was approved by the Board of Directors on April 1, 2002.

There have been no disagreements with our independent accountants on our accounting or financial reporting that would require our independent accountants to qualify or disclaim their report on our financial statements, or otherwise require disclosure in this Form 10-K.

PART III

ITEM 10. DIRECTORS AND EXECUTIVE OFFICERS OF THE REGISTRANT

The information required in response to this item is set forth in the Company's definitive proxy statement for the annual meeting of stockholders to be held on April 30, 2003 and is incorporated herein by reference.

ITEM 11. EXECUTIVE COMPENSATION

The information required in response to this item is set forth in the Company's definitive proxy statement for the annual meeting of stockholders to be held on April 30, 2003 and is incorporated herein by reference.

ITEM 12. SECURITY OWNERSHIP OF CERTAIN BENEFICIAL OWNERS AND MANAGEMENT

The information required in response to this item is set forth in the Company's definitive proxy statement for the annual meeting of stockholders to be held on April 30, 2003 and is incorporated herein by reference.

ITEM 13. CERTAIN RELATIONSHIPS AND RELATED TRANSACTIONS

The information required in response to this item is set forth in the Company's definitive proxy statement for the annual meeting of stockholders to be held on April 30, 2003 and is incorporated herein by reference.

ITEM 14. CONTROLS AND PROCEDURES

Our Chief Executive Officer and our Chief Financial Officer (our principal executive officer and principal financial officer, respectively) have concluded, based on their evaluation as of a date within 90 days prior to the date of the filing of this annual report on Form 10-K, that our disclosure controls and procedures are effective to ensure that information required to be disclosed by us in the reports filed or submitted by us under the Securities Exchange Act of 1934, as amended, is recorded, processed, summarized and reported within the time periods specified in the SEC's rules and forms, and include controls and procedures designed to ensure that information required to be disclosed by us in such reports is accumulated and communicated to our management, including our Chief Executive Officer and our Chief Financial Officer, as appropriate to allow timely decisions regarding required disclosure. No significant changes in our disclosure controls and procedures or corrective actions have been made subsequent to the date of such evaluation that could significantly affect these controls.

PART IV

ITEM 15. EXHIBITS, FINANCIAL STATEMENT SCHEDULES, AND REPORTS ON FORM 8-K

(a) The following documents are filed as a part of this Report at page 38:

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) Reports on Form 8-K

The Company filed the following reports on Form 8-K during the quarter ended December 31, 2002 and through March 14, 2003:

On December 6, 2002, the Company filed a current report on Form 8-K announcing the filing of amendments to its 2001 Annual Report on Form 10-K and its Quarterly Reports on Form 10-Q for the first three quarters of 2002.

On February 3, 2003, the Company filed a current report on Form 8-K announcing year end 2002 reserves, production, and finding and development costs.

On February 13, 2003, the Company filed a current report on Form 8-K announcing full year and fourth quarter 2002 results.

(c) Exhibits

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

EXHIBIT NUMBER	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 Encore Acquisition 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 Encore, 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	Registration Rights Agreement, dated June 19, 2002, among Encore, the subsidiary guarantors party thereto and the initial purchasers named therein (incorporated by reference

	to Exhibit 4.2 to Quarterly Report on Form 10-Q for the quarterly period ended June 30, 2002, filed with the SEC on August 9, 2002).
4.4*	Form of 8 3/8% Senior Subordinated Note to Cede & Co. or its registered assigns, dated January 16, 2003.
10.1**	2000 Incentive Stock Plan (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 14, 2002).
10.2	Credit Agreement, dated June 25, 2002 among Encore Acquisition Company, Encore Operating, L.P., Fleet National Bank, a national banking association, as Administrative Agent, Wachovia Bank, N.A., as Syndication Agent, Fortis Capital Corp., as Documentary Agent and the financial institutions listed therein (incorporated by reference to Exhibit 10.1 to Quarterly Report on Form 10-Q for the quarterly period ended June 30, 2002, filed with the SEC on August 9, 2002).
10.3*	Form of Facility Guaranty by the Encore's subsidiary guarantors in favor of Fleet National Bank and the other lenders under the Credit Agreement referred to under Exhibit 10.2 above.
16.1	Current Report on Form 8-K, filed with the SEC on April 5, 2002, regarding the dismissal of independent auditor.
21.1	Subsidiaries of Encore Acquisition Company (incorporated by reference to Exhibit 21.1 to Annual Report on Form 10-K for the annual period ended December 31, 2001, filed with the SEC on March 15, 2002).
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).
99.1*	Certification Pursuant to 18 U.S.C. Section 1350, as Adopted Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
99.2*	Certification Pursuant to 18 U.S.C. Section 1350, as Adopted Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.

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* Filed herewith

** Compensatory plan

Copies of the above exhibits not contained herein are available at the cost of reproduction to any security holder upon written request to the Assistant Treasurer, Encore Acquisition Company, 777 Main Street, Suite 1400, Fort Worth, Texas 76102.

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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 24th day of March, 2003.

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 Morris B. Smith, 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 and in the capacities and on March 24, 2003.

SIGNATURE	TITLE OR CAPACITY
/s/ I. JON BRUMLEY I. Jon Brumley	Chairman of the Board, Chief Executive Officer, and Director
/s/ JON S. BRUMLEY Jon S. Brumley	President and Director
/s/ MORRIS B. SMITH Morris B. Smith	Chief Financial Officer, Treasurer, Executive Vice President, Secretary and Principal Financial Officer
/s/ ROBERT C. REEVES Robert C. Reeves	Vice President, Controller, and Principal Accounting Officer
/s/ ARNOLD L. CHAVKIN Arnold L. Chavkin	Director
/s/ HOWARD H. NEWMAN Howard H. Newman	Director
/s/ TED A. GARDNER Ted A. Gardner	Director

SIGNATURE TITLE OR CAPACITY

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/s/ TED COLLINS, JR. Director

Ted Collins, Jr.

/s/ JAMES A. WINNE, III Director

James A. Winne, III

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CERTIFICATIONS

I, I. Jon Brumley, Chairman of the Board and Chief Executive Officer of Encore Acquisition Company, certify that:

1. I have reviewed this annual report on Form 10-K of Encore Acquisition Company;

2. Based on my knowledge, this annual report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this annual report;

3. Based on my knowledge, the financial statements, and other financial information included in this annual report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this annual report;

4. The registrant's other certifying officers and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-14 and 15d-14) for the registrant and have:

(a) Designed such disclosure controls and procedures to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this annual report is being prepared;

(b) Evaluated the effectiveness of the registrant's disclosure controls and procedures as of a date within 90 days prior to the filing date of this annual report (the "Evaluation Date"); and

(c) Presented in this annual report our conclusions about the effectiveness of the disclosure controls and procedures based on our evaluation as of the Evaluation Date;

5. The registrant's other certifying officers and I have disclosed, based on our most recent evaluation, to the registrant's auditors and the audit committee of registrant's board of directors (or persons performing the equivalent functions):

(a) All significant deficiencies in the design or operation of internal controls which could adversely affect the registrant's ability to record, process, summarize and report financial data and have identified for the registrant's auditors any material weaknesses in internal controls; and

(b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal controls; and

6. The registrant's other certifying officers and I have indicated in this annual report whether there were significant changes in internal controls or in other factors that could significantly affect internal controls subsequent to the date of our most recent evaluation, including any corrective actions with regard to significant deficiencies and material weaknesses.

/s/ I. JON BRUMLEY

I. Jon Brumley
Chairman of the Board and Chief Executive Officer
of Encore Acquisition Company

Date: March 24, 2003

CERTIFICATIONS

I, Morris B. Smith, Chief Financial Officer, Treasurer, Executive Vice President and Secretary of Encore Acquisition Company, certify that:

1. I have reviewed this annual report on Form 10-K of Encore Acquisition Company;

2. Based on my knowledge, this annual report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this annual report;

3. Based on my knowledge, the financial statements, and other financial information included in this annual report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this annual report;

4. The registrant's other certifying officers and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-14 and 15d-14) for the registrant and have:

(a) Designed such disclosure controls and procedures to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this annual report is being prepared;

(b) Evaluated the effectiveness of the registrant's disclosure controls and procedures as of a date within 90 days prior to the filing date of this annual report (the "Evaluation Date"); and

(c) Presented in this annual report our conclusions about the effectiveness of the disclosure controls and procedures based on our evaluation as of the Evaluation Date;

5. The registrant's other certifying officers and I have disclosed, based on our most recent evaluation, to the registrant's auditors and the audit committee of registrant's board of directors (or persons performing the

equivalent functions):

(a) All significant deficiencies in the design or operation of internal controls which could adversely affect the registrant's ability to record, process, summarize and report financial data and have identified for the registrant's auditors any material weaknesses in internal controls; and

(b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal controls; and

6. The registrant's other certifying officers and I have indicated in this annual report whether there were significant changes in internal controls or in other factors that could significantly affect internal controls subsequent to the date of our most recent evaluation, including any corrective actions with regard to significant deficiencies and material weaknesses.

/s/ MORRIS B. SMITH

Morris B. Smith
Chief Financial Officer, Treasurer,
Executive Vice President and Secretary
of Encore Acquisition Company

Date: March 24, 2003

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