DENBURY RESOURCES INC

FORM 10-K
(Annual Report)

Filed 03/25/02 for the Period Ending 12/31/01

Address	5320 LEGACY DRIVE PLANO, TX 75024
Telephone	9726732000
CIK	0000945764
Symbol	DNR
SIC Code	1311 - Crude Petroleum and Natural Gas
Industry	Oil & Gas Operations
Sector	Energy
Fiscal Year	12/31

DENBURY RESOURCES INC

FORM 10-K
(Annual Report)

Filed 3/25/2002 For Period Ending 12/31/2001

Address	5100 TENNYSON PARKWAY SUITE 3000
	PLANO, Texas 75024
Telephone	972-673-2000
CIK	0000945764
Industry	Oil & Gas Operations
Sector	Energy
Fiscal Year	12/31

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

2001 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, 2001

OR

|_| Transition report pursuant to Section 13 or 15(d)
of the Securities Exchange Act of 1934

For the transition period from _________ to________

Commission file number 1-12935

DENBURY RESOURCES INC.
(Exact name of Registrant as specified in its charter)

Delaware (State or other jurisdiction of incorporation or organization)	75-2815171 (I.R.S. Employer Identification No.)
5100 Tennyson Parkway, Suite 3000, Plano, TX (Address of principal executive offices)	75024 (Zip Code)
Registrant's telephone number, including area code:	(972) 673-2000

Securities registered pursuant to Section 12(b) of the Act:

Title of Each Class	Name of Each Exchange on Which Registered
Common Stock $.001 Par Value	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. [X] Yes [ ] 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. [ ]

As of March 15, 2002, the aggregate market value of the registrant's Common Stock held by non-affiliates was approximately $185,463,000.

The number of shares outstanding of the registrant's Common Stock as of March 15, 2002, was 53,008,246.

DOCUMENTS INCORPORATED BY REFERENCE

Document	Incorporated as to
1. Notice and Proxy Statement for the Annual Meeting of Shareholders to be held May 22, 2002.	1. Part III, Items 10, 11, 12, and 13

2. Annual Report to Shareholders for the year ended December 31, 2001.	2. Part 1, Item 1 and Part II, Items 5, 6, 7, 8

PART I

Item 1. Business

The Company

Denbury Resources Inc. ("Denbury" or the "Company") is a Delaware corporation, organized under Delaware General Corporation Law, engaged in the acquisition, development, operation and exploration of oil and gas properties in the Gulf Coast region of the United States, primarily in Louisiana and Mississippi. Denbury's corporate headquarters is located at 5100 Tennyson Parkway, Suite 3000, Plano, Texas 75024, and its phone number is 972-673-2000. At December 31, 2001, the Company had 320 employees, 211 of which were employed in field operations or at the field offices.

Incorporation and Organization

Denbury was originally incorporated in Canada in 1951. In 1992, the Company acquired all of the shares of a United States operating company, Denbury Management, Inc. ("DMI"), and subsequent to the merger the Company sold all of its Canadian assets. Since that time, all of the Company's operations have been in the United States.

In April 1999, the stockholders approved a move of the Company's corporate domicile from Canada to the United States as a Delaware corporation. Along with the move, the Company's wholly owned subsidiary, DMI, was merged into the new Delaware parent company, Denbury Resources Inc. This move of domicile did not have any effect on the operations and assets of the Company.

The Company has three active wholly owned subsidiaries, Denbury Marine, L.L.C., Denbury Energy Services, Inc. and Denbury Offshore, Inc.

Business Strategy

As part of our corporate strategy, we believe in the following fundamental principles:

o remain focused in specific regions;

o acquire properties where we believe additional value can be created through a combination of exploitation, development, exploration and marketing;

o acquire properties that give us a majority working interest and operational control or where we believe we can ultimately obtain it;

o maximize the value of our properties by increasing production and reserves while reducing cost; and

o maintain a highly competitive team of experienced and incentivized personnel.

Acquisitions

Information as to recent acquisitions by the Company is set forth under "Management's Discussion and Analysis of Financial Condition and Results of Operations - 2001 Acquisitions," appearing on pages 29 through 30 of the Annual Report and under Note 2, "Acquisitions," of the Consolidated Financial Statements. Such information is incorporated herein by reference.

Oil and Gas Operations

Information regarding selected operating data and a discussion of the Company's significant operating areas and the primary properties within those three areas are set forth under "Selected Operating Data," appearing on pages 8 through 11 of the Annual Report, and the Operations Sections appearing on pages 14 through 25 of the Annual Report. Such information is incorporated herein by reference.

Oil and Gas Acreage, Productive Wells, Drilling Activity

Information regarding oil and gas acreage, productive wells and drilling activity are set forth under "Selected Operating Data," appearing on page 11 of the Annual Report.

Title to Properties

Customarily in the oil and gas industry, only a perfunctory title examination is conducted at the time properties believed to be suitable for drilling operations are first acquired. Prior to commencement of drilling operations, a thorough drill site title examination is normally conducted, and curative work is performed with respect to significant defects. During acquisitions, title reviews are performed on all properties; however, formal title opinions are obtained on only the higher value properties. The Company believes that it has good title to its oil and natural gas properties, some of which are subject to minor encumbrances, easements and restrictions.

Production

Information regarding average production rates, unit sale prices and unit costs per BOE are set forth under "Management's Discussion and Analysis of Financial Condition and Results of Operations" appearing on pages 36 through 39 of the Annual Report.

Geographic Segments

All of the Company's operations are in the United States.

Significant Oil and Gas Purchasers and Product Marketing

Oil and gas sales are made on a day-to-day basis under short-term contracts at the current area market price. The loss of any purchaser would not be expected to have a material adverse effect upon the Company. For the year ended December 31, 2001, the Company sold 10% or more of its net production of oil and gas to the following purchasers: Conoco 14%, Hunt Refining 13%, EOTT Energy 12% and Dynegy 12%.

The Company's ability to market oil and gas depends on many factors beyond its control, including the extent of domestic production and imports of oil and gas, the proximity of the Company's gas production to pipelines, the available capacity in such pipelines, the demand for oil and gas, the effects of weather, and the effects of state and federal regulation. Denbury's production is primarily from developed fields close to major pipelines or refineries and established infrastructure. As a result, Denbury has not experienced any difficulty to date in finding a market for all of its product as it becomes available or in transporting its product to these markets; however, the Company cannot assure that it will always be able to market all of its production or obtain favorable prices. The Company does not currently believe that the loss of any of its oil or gas purchasers would have a material adverse effect on its operations.

Oil Marketing

Denbury markets its oil to a variety of purchasers, many of which are large, established companies. The oil is generally sold under a short-term contract with the sales price based on an applicable posted price, plus a negotiated premium or the NYMEX price less a discount. This price is determined on a well-by-well basis and the purchaser generally takes delivery at the wellhead. Mississippi oil, which accounted for approximately 86% of the Company's oil production in 2001, is primarily light to medium sour crude and sells at a significant discount to the NYMEX price. This discount ranged by field from approximately $0.22 to $9.62 per Bbl in 2001 and the average discount for the Company's Mississippi oil production was approximately $4.78 per Bbl in 2001. The balance of the oil production, Louisiana oil, is primarily light sweet crude, which typically sells at a small discount to NYMEX.

Natural Gas Marketing

Virtually all of Denbury's natural gas production is close to existing pipelines and consequently, the Company generally has a variety of options to market its natural gas. The Company sells the majority of its natural gas on one year contracts with prices fluctuating month-to-month based on published pipeline indices with slight premiums or discounts to the index.

Product Price Derivative Hedging Contracts

The Company enters into various financial contracts to hedge its exposure to commodity price risk associated with anticipated future oil and natural gas production. Information as to these activities is set forth under "Management's Discussion and Analysis of Financial Condition and Results of Operations - Market Risk Management," appearing on pages 44 through 48 of the Annual Report and under Note 7, "Derivative Hedging Contracts," of the Consolidated Financial Statements. Such information is incorporated herein by reference.

Operating Environment

Oil and Natural Gas Price Volatility

The Company's future financial condition, results of operations and the carrying value of our oil and natural gas properties depends primarily upon the prices the Company receives for its oil and natural gas production. Oil and natural gas prices historically have been volatile and likely will continue to be volatile in the future. This price volatility also affects the amount of cash flow available to the Company for capital expenditures and the Company's ability to borrow money or raise additional capital. The amount the Company can borrow or have outstanding under its bank credit facility is subject to semi-annual redeterminations based on current prices at the time of redetermination. In the short-term, the Company's production is balanced between oil and natural gas, but longer-term, oil prices are likely to have a greater impact on the Company because 70% of the Company's reserves are oil.

Over the last three years oil prices have gone from near historic low prices to higher prices not experienced for at least ten years. At the end of 1998, NYMEX oil prices were at historic lows of approximately $12.00 per Bbl, but during 1999 and 2000 NYMEX oil prices increased to an average of approximately $19.30 and $30.25 per Bbl, respectively. During 2001, NYMEX oil prices declined to an average of approximately $26.00 per Bbl and were at $19.84 per Bbl at the end of 2001. Natural gas prices have experienced even more volatility over the same three year period. During 1999 natural gas prices averaged approximately $2.35 per Mcf and increased to an average of approximately $3.90 per Mcf during 2000, primarily due to low storage levels. At December 31, 2000, NYMEX natural gas prices were almost $10.00 per Mcf but declined steadily during 2001 as supplies of natural gas increased. As of year-end 2001, natural gas prices had declined to $2.57 per Mcf.

The prices for oil and natural gas are subject to wide fluctuations in response to relatively minor changes in the supply of and demand for oil and natural gas, market uncertainty and a variety of additional factors that are beyond our control. These factors include:

o relatively minor changes in the supply of and demand for oil and natural gas;

o weather conditions;

o market uncertainty;

o domestic and foreign governmental regulations and taxes;

o the availability and cost of alternative fuel sources;

o the domestic and foreign supply of oil and natural gas;

o the price of foreign oil and natural gas;

o the ability of the members of the Organization of Petroleum Exporting Countries to agree to and maintain oil price and production controls;

o political conditions in oil and natural gas producing regions, including the Middle East; and

o overall economic conditions.

These factors and the volatility of the energy markets generally make it extremely difficult to predict future oil and natural gas price movements with any certainty. Declines in oil and natural gas prices would not only reduce revenue, but could reduce the amount of oil and natural gas that we can produce economically and, as a result, could have a material adverse effect on our financial condition, results of operations and reserves. Further, oil and natural gas prices do not necessarily move in tandem.

Oil and Natural Gas Drilling and Producing Operations

Drilling activities are subject to many risks, including the risk that no commercially productive reservoirs will be discovered. There can be no assurance that new wells drilled by the Company will be productive or that the Company will recover all or any portion of our investment in such wells. Drilling for oil and natural gas may involve unprofitable efforts, not only from dry wells but also from wells that are productive but do not produce sufficient net reserves to return a profit after deducting drilling, operating and other costs. The seismic data and other technologies used by the Company do not provide conclusive knowledge, prior to drilling a well, that oil or natural gas is present or may be produced economically. The cost of drilling, completing and operating a well is often uncertain, and cost factors can adversely affect the economics of a project. Further, the Company's drilling operations may be curtailed, delayed or canceled as a result of numerous factors, including:

o unexpected drilling conditions;

o title problems;

o pressure or irregularities in formations;

o equipment failures or accidents;

o adverse weather conditions;

o compliance with environmental and other governmental requirements; and

o cost of, or shortages or delays in the availability of, drilling rigs, equipment and services.

The Company's operations are subject to all the risks normally incident to the operation and development of oil and natural gas properties and the drilling of oil and natural gas wells, including encountering well blowouts, cratering and explosions, pipe failure, fires, formations with abnormal pressures, uncontrollable flows of oil, natural gas, brine or well fluids, release of contaminants into the environment and other environmental hazards and risks.

In accordance with industry practice, the Company maintains insurance against some, but not all, of the risks described above in an amount the Company believes to be adequate. However, the nature of these risks is such that some liabilities could exceed the Company's policy limits, or, as in the case of environmental fines and penalties, cannot be insured. The Company could incur significant costs that could have a material adverse effect upon its financial condition due to these risks.

Future Performance and Acquisitions

Unless the Company can successfully replace the reserves that we produce, the Company's reserves will decline, resulting eventually in a decrease in oil and natural gas production and lower revenues and cash flows from operations. The Company has historically replaced reserves through both drilling and acquisitions. In the future the Company may not be able to continue to replace reserves at acceptable costs. The business of exploring for, developing or acquiring reserves is capital intensive. The Company may not be able to make the necessary capital investment to maintain or expand its oil and natural gas reserves if cash flows from operations are reduced, due to lower oil or natural gas prices or otherwise, or if external sources of capital become limited or unavailable. If the Company does not continue to make significant capital expenditures, or if outside capital resources become limited, the Company may not be able to maintain its growth rate. In addition, the Company's drilling activities are subject to numerous risks, including the risk that no commercially productive oil or natural gas reserves will be encountered. Exploratory drilling involves more risk than development drilling because exploratory drilling is designed to test formations for which proved reserves have not been discovered.

The Company is continually identifying and evaluating acquisition opportunities, such as our recently completed Matrix acquisition, which substantially increased our offshore operations. However, the magnitude of an acquisition such as Matrix, together with the inherent difficulty in evaluating the acquired properties and forecasting reserves, may result in the Company's inability to achieve or maintain targeted production levels. In that case, the Company's ability to realize the total economic benefit from the acquisition may be reduced or eliminated. There can be no assurance that the Company will successfully consummate any future acquisitions or that such acquisitions of oil and natural gas properties will contain economically recoverable reserves or that any future acquisition will be profitably integrated into the Company's operations.

Competition and Markets

The Company faces competition from other oil and gas companies in all aspects of its business, including acquisition of producing properties and oil and gas leases, marketing of oil and gas, and obtaining goods, services and labor. Many of its competitors have substantially larger financial and other resources. Factors that affect the Company's ability to acquire producing properties include available funds, available information about prospective properties and the Company's standards established for minimum projected return on investment. Gathering systems are the only practical method for the intermediate transportation of natural gas. Therefore, competition for natural gas delivery is presented by other pipelines and gas gathering systems. Competition is also presented by alternative fuel sources, including heating oil and other fossil fuels. Because of the long-lived, high margin nature of the Company's oil and gas reserves and management's experience and expertise in exploiting these reserves, management believes that it is effective in competing in the market.

Federal and State Regulations

There have been, and continue to be, numerous federal and state laws and regulations governing the oil and gas industry that are often changed in response to the current political or economic environment. Compliance with this regulatory burden is often difficult and costly and may carry substantial penalties for noncompliance. The following are some specific regulations that may affect the Company. The Company cannot predict the impact of these or future legislative or regulatory initiatives.

Regulation of Natural Gas and Oil Exploration and Production

The Company's operations are subject to various types of regulation at the federal, state and local levels. Such regulation includes requiring permits for drilling wells, maintaining bonding requirements in order to drill or operate wells and regulating the location of wells, the method of drilling and casing wells, the surface use and restoration of properties upon which wells are drilled, the plugging and abandoning of wells and the disposal of fluids used in connection with operations. The Company's operations are also subject to various conservation laws and regulations. These include the regulation of the size of drilling and spacing units or proration units and the density of wells which may be drilled in and the unitization or pooling of oil and gas properties. In addition, state conservation laws establish maximum rates of production from oil and gas wells, generally prohibit the venting or flaring of gas and impose certain requirements regarding the ratability of production. The effect of these regulations may limit the amount of oil and gas the Company can produce from its wells and may limit the number of wells or the locations at which the Company can drill. The regulatory burden on the oil and gas industry increases the Company's costs of doing business and, consequently, affects its profitability. Inasmuch as such laws and regulations are frequently expanded, amended and reinterpreted, the Company is unable to predict the future cost or impact of complying with such regulations.

Federal Regulation of Sales Prices and Transportation

Currently, there are no federal, state or local laws that regulate the price for sales of natural gas, NGLs, crude oil or condensate by the Company. However, the rates charged and terms and conditions for the movement of gas in interstate commerce through certain intrastate pipelines and production area hubs are subject to regulation under the Natural Gas Policy Act of 1978 ("NGPA"). Pipeline and hub construction activities are, to a limited extent, also subject to regulations under the Natural Gas Act of 1938 ("NGA"). While these controls do not apply directly to the Company, their effect on natural gas markets can be significant in terms of competition and cost of transportation services. Additional proposals and proceedings that might affect the natural gas industry are considered from time to time by Congress, FERC, state regulatory bodies and the courts. The Company cannot predict when or if any such proposals might become effective and their effect, if any, on the Company's operations. Historically, the natural gas industry has been heavily regulated; therefore, there is no assurance that the less stringent regulatory approach recently pursued by FERC, Congress and the states will continue indefinitely into the future.

Gathering Regulations

State regulation of gathering facilities generally includes various safety, environmental and, in some circumstances, nondiscriminatory take requirements. Such regulation has not generally been applied against gatherers of natural gas, although natural gas gathering may receive greater regulatory scrutiny in the future.

Federal, State or Indian Leases

The Company's operations on federal, state or Indian oil and 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

Public interest in the protection of the environment has increased dramatically in recent years. In addition, over the last two years the Company has acquired significant assets offshore in the Gulf of Mexico which are regulated by the Minerals Management Service of the U.S. Department of the Interior. The Company's oil and natural gas production and saltwater disposal operations and our processing, handling and disposal of hazardous materials, such as hydrocarbons and naturally occurring radioactive materials are subject to stringent regulation. The Company could incur significant costs, including cleanup costs resulting from a release of hazardous material, third-party claims for property damage and personal injuries fines and sanctions, as a result of any violations or liabilities under environmental or other laws. Changes in or more stringent enforcement of environmental laws could also result in additional operating costs and capital expenditures.

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 gas exploration, development and production operations, and consequently may impact the Company's operations and costs. These regulations include, among others, (i) regulations by the EPA and various state agencies regarding approved methods of disposal for certain hazardous and nonhazardous wastes; (ii) the Comprehensive Environmental Response, Compensation, and Liability Act, Federal Resource Conservation and Recovery Act and analogous state laws which regulate the removal or remediation of previously disposed wastes (including wastes disposed of or released by prior owners or operators), property contamination (including groundwater contamination), and remedial plugging operations to prevent future contamination; (iii) the Clean Air Act and comparable state and local requirements which may result in the gradual imposition of certain pollution control requirements with respect to air emissions from the operations of the Company; (iv) the Oil Pollution Act of 1990 which contains numerous requirements relating to the prevention of and response to oil spills into waters of the United States; (v) the Resource Conservation and Recovery Act which is the principal federal statute governing the treatment, storage and disposal of hazardous wastes; and (vi) state regulations and statutes governing the handling, treatment, storage and disposal of naturally occurring radioactive material ("NORM").

Management believes that the Company is in substantial compliance with applicable environmental laws and regulations. To date, the Company has 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 the Company.

Estimated Net Quantities of Proved Oil and Gas Reserves and Present Value of Estimated Future Net Revenues

Estimates of net proved oil and gas reserves as of December 31, 2001 and 2000 have been prepared by DeGolyer and MacNaughton, and the estimates as of December 31, 1999 were prepared by Netherland, Sewell and Associates, Inc., both independent petroleum engineers located in Dallas, Texas. See Note 11, "Supplemental Oil and Natural Gas Disclosures," of the Consolidated Financial Statements and pages 9 and 10 of the Annual Report for disclosure of reserve data. Such information is incorporated herein by reference.

There are numerous uncertainties inherent in estimating quantities of proved oil and natural gas reserves and their values, including many factors beyond our control. The reserve data included herein represents only estimates. Reserve engineering is a subjective process of estimating underground accumulations of oil and natural gas that cannot be measured in an exact manner. The accuracy of any reserve estimate is a function of the quality of available geological, geophysical, engineering and economic data, the precision of the engineering and judgment. As a result, estimates of different engineers often vary. The estimates of reserves, future cash flows and present value are based on various assumptions, including those prescribed by the SEC relating to oil and natural gas prices, drilling and operating expenses, capital expenditures, taxes and availability of funds, and are inherently imprecise. Actual future production, cash flows, taxes, development expenditures, operating expenses and quantities of recoverable oil and natural gas reserves may vary substantially from the Company's estimates. Such variations may be significant and could materially affect estimated quantities and the present value of the Company's proved reserves. Also, the use of a 10% discount factor for reporting purposes may not necessarily represent the most appropriate discount factor, given actual interest rates and risks to which the Company or the oil and natural gas industry in general are subject.

You should not assume that the present values referred to herein represent the current market value of our estimated oil and natural gas reserves. In accordance with requirements of the SEC, the estimates of present values are based on prices and costs as of the date of the estimates. Actual future prices and costs may be materially higher or lower than the prices and cost as of the date of the estimate.

Quantities of proved reserves are estimated based on economic conditions, including oil and natural gas prices in existence at the date of assessment. The Company's reserves and future cash flows may be subject to revisions based upon changes in economic conditions, including oil and natural gas prices, as well as due to production results, results of future development, operating and development costs and other factors. Downward revisions of the Company's reserves could have an adverse affect on its financial condition and operating results.

Item 2. Properties

See Item 1. Business - "Oil and Gas Operations." The Company also has various operating leases for rental of office space, office equipment, and vehicles. See Note 9, "Commitments and Contingencies," of the Consolidated Financial Statements for the future minimum rental payments. Such information is incorporated herein by reference.

Item 3. Legal Proceedings

In the opinion of management, there are no material pending legal proceedings to which the Company or any of its subsidiaries is a party or of which any of their property is the subject. However, due to the nature of its business, certain legal or administrative proceedings arise from time to time in the ordinary course of its business. See Note 9, "Commitments and Contingencies," of the Consolidated Financial Statements for further disclosure regarding legal proceedings and contingencies. Such information is included herein by reference.

Item 4. Submission of Matters to a Vote of Security Holders

No matters were submitted for a vote of security holders during the fourth quarter of 2001.

PART II

Item 5. Market for the Common Stock and Related Matters

Information as to the markets in which the Company's common stock is traded, the quarterly high and low prices for such stock during the last two years, the restriction on the payment of dividends with respect to the common stock, and the approximate number of stockholders of record at February 1, 2002, is set forth under "Common Stock Trading Summary" appearing on page 81 of the Annual Report. Such information is incorporated herein by reference.

Affiliates of the Texas Pacific Group beneficially own approximately 52% of the Company's outstanding common stock and their representatives hold four of nine seats on the Company's board of directors. As a result of its ownership, the Texas Pacific Group has the effective ability to elect all directors of the Company and to control its business and affairs, including decisions with respect to the acquisition or disposition of assets, the future issuance of our common stock or other securities, dividend policy and decisions with respect to the Company's drilling, operating and acquisition expenditure plans. Although the Company's articles of incorporation require a two-thirds majority vote by the board of directors on most significant transactions, such as significant asset purchases and sales, issuances of equity and debt, changes in the board of directors and other matters, there is no agreement that would prevent the Texas Pacific Group from replacing all directors of the Company by calling a meeting of the Company's shareholders.

Item 6. Selected Financial Data

Selected Financial Data for the Company for each of the last five years are set forth under "Financial Highlights" appearing on page 2 of the Annual Report. All such information is incorporated herein by reference.

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

Information as to the Company's financial condition, changes in financial condition and results of operations and other matters is set forth in "Management's Discussion and Analysis of Financial Condition and Results of Operations," appearing on pages 29 through 50 of the Annual Report and is incorporated herein by reference.

Item 7A. Quantitative and Qualitative Disclosures About Market Risk

The information required by Item 7A is set forth under "Market Risk Management" in "Management's Discussion and Analysis of Financial Condition and Results of Operations," appearing on pages 44 through 48 of the Annual Report and is incorporated herein by reference.

Item 8. Financial Statements and Supplementary Data

The Company's consolidated financial statements, accounting policy disclosures, notes to financial statements, business segment information, unaudited quarterly information and independent auditors' report are presented on pages 51 through 81 of the Annual Report. All such information is incorporated herein by reference.

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

None.

PART III

Item 10. Directors and Executive Officers of the Company

Directors of the Company

Information as to the names, ages, positions and offices with Denbury, terms of office, periods of service, business experience during the past five years and certain other directorships held by each director or person nominated to become a director of Denbury will be set forth in the "Election of Directors" segment of the Proxy Statement ("Proxy Statement") for the Annual Meeting of Shareholders to be held May 22, 2002, ("Annual Meeting") and is incorporated herein by reference.

Executive Officers of the Company

Information concerning the executive officers of Denbury will be set forth in the "Management" section of the Proxy Statement for the Annual Meeting and is incorporated herein by reference.

Section 16(a) Beneficial Ownership Reporting Compliance

Section 16(a) of the Securities Exchange Act of 1934 and the rules thereunder require the Company's executive officers and directors, and persons who beneficially own more than ten percent (10%) of a registered class of the Company's equity securities, to file reports of ownership and changes in ownership with the Securities and Exchange Commission and exchanges and to furnish the Company with copies. Based solely on its review of the copies of such forms received by it, or written representations from such persons, the Company is not aware of any person who failed to file any reports required by
Section 16(a) to be filed for fiscal 2001. The Company is aware of delinquent filings on behalf of three officers and directors that will be disclosed in the Company's Proxy Statement and is incorporated herein by reference.

Item 11. Executive Compensation

Information concerning remuneration received by Denbury's executive officers and directors will be presented under the caption "Statement of Executive Compensation" in the Proxy Statement for the Annual Meeting and is incorporated herein by reference.

Item 12. Security Ownership of Certain Beneficial Owners and Management

Information as to the number of shares of Denbury's equity securities beneficially owned as of March 15, 2002, by each of its directors and nominees for director, its five most highly compensated executive officers and its directors and executive officers as a group will be presented under the caption "Security Ownership of Certain Beneficial Owners and Management" in the Proxy Statement for the Annual Meeting and is incorporated herein by reference.

Item 13. Certain Relationships and Related Transactions

Information on related transactions will be presented under the caption "Compensation Committee Interlocks and Insider Participation" and "Interests of Insiders in Material Transactions" in the Proxy Statement for the Annual Meeting and is incorporated herein by reference.

PART IV

Item 14. Exhibits, Financial Statement Schedules and Reports on Form 8-K

(a) Financial Statements and Schedules. Financial statements and schedules filed as a part of this report are presented on pages 51 through 81 of the Annual Report and are incorporated herein by reference.

Exhibits. The following exhibits are filed as a part of this report.

Exhibit No.	Exhibit
3(a)	Certificate of Incorporation of Denbury Resources Inc. filed with the Delaware Secretary of State on April 20, 1999 (incorporated by reference as Exhibit 3(a) of the Registrant's Form 10-Q for the quarter ended March 31, 1999).
3(b)	Bylaws of Denbury Resources Inc., a Delaware corporation, adopted April 20, 1999 (incorporated by reference as Exhibit 3(b) of the Registrant's Form 10-Q for the quarter ended March 31, 1999).
4(a)	Form of Indenture between Denbury Management Inc. and Chase Bank of Texas, National Association, as trustee (incorporated by reference as Exhibit 4(b) of Registrant's Registration Statement on Form S-3 dated February 19, 1998).
4(b)	First Supplemental Indenture dated as of April 21, 1999, between Denbury Resources Inc., a Delaware corporation, and Chase Bank of Texas, National Association, as Trustee, relating to Denbury Management, Inc.'s 9% Senior Subordinated Notes due 2008 (incorporated by reference to Exhibit 4(a) of the Registrant's Form 10-Q for the quarter ended March 31, 1999).
4(c)	Indenture dated as of August 15, 2001, among Denbury Resources Inc., certain of its subsidiaries, and the Chase Manhattan Bank (incorporated by reference as Exhibit 4(c) of the Registrant's Registration Statement on Form S-4 dated October 23, 2001).
4(d)	Registration Rights Agreement dated August 8, 2001 (incorporated by reference as Exhibit 4(d) of the Registrant's Registration Statement on Form S-4 dated October 23, 2001).
10(a)	Second Amended and Restated Credit Agreement, dated October 13, 2000, between the Company and Bank of America, N.A., as Administrative Agent, and the financial institutions listed on schedule 2.1 therein (incorporated by reference to Exhibit 10 of the Registrant's Form 10-Q for the quarter ended September 30, 2000).
10(b)**	Denbury Resources Inc. Stock Option Plan (incorporated by reference as Exhibit 4(f) of the Registrant's Registration Statement on Form S-8, No. 333-1006, dated February 2, 1996, and as amended by the Registrant's Registration Statements on Forms S-8, Nos. 333-27995, 333-55999, 333-70485, and 333-63198 dated May 29, 1997, June 4, 1998, July 12, 1999 and June 15, 2001, respectively).

Exhibit No.	Exhibit
10(c)**	Denbury Resources Inc. Stock Purchase Plan (incorporated by reference as Exhibit 4(g) of the Registrant's Registration Statement on Form S-8, No. 333-1006, dated February 2, 1996, and as amended by the Registrant's Registration Statements on Forms S-8, No. 333-70485, dated January 12, 1999 and No. 333-39172, dated June 13, 2000).
10(d)	Form of indemnification agreement between Denbury Resources Inc. and its officers and directors (incorporated by reference as Exhibit 10 of the Registrant's Form 10-Q for the quarter ended June 30, 1999).
10(e)**	Denbury Resources Inc. Directors Compensation Plan (incorporated by reference as Exhibit 4 of the Registrant's Registration Statement on Form S-8, No. 333-39172, dated June 13, 2000 and amended March 2, 2001).
10(f)**	Denbury Resources Severance Protection Plan, dated December 6, 2000 (incorporated by reference as Exhibit 10(f) of the Registrant's Form 10-K for the year ended December 31, 2001).
10(g)	Stock Purchase Agreement between TPG Partners II, L.L.C. and the Company dated as of December 16, 1998 (incorporated by reference as Exhibit 99.1 of the Registrant's Form 8-K dated December 17, 1998).
10(h)	Agreement and Plan of Merger and Reorganization, by and among Denbury Resources Inc., Denbury Offshore, Inc., and Matrix Oil & Gas, Inc., and its shareholders, as of June 4, 2001 (incorporated by reference as Exhibit 2 of the Registrant's Current Report on Form 8-K, dated June 15, 2001).
13*	Annual Report to Shareholders.
21*	List of Subsidiaries of Denbury Resources Inc.
23*	Consent of Deloitte & Touche LLP.

* Filed herewith. ** Compensation arrangements.

(b) Reports on Form 8-K.

None

SIGNATURES

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

DENBURY RESOURCES INC.

March 20, 2002	*/s/ Phil Rykhoek* -------------------------------------- *Phil Rykhoek* *Chief Financial Officer and Secretary*
March 20, 2002	*/s/ Mark C. Allen* -------------------------------------- *Mark C. Allen* *Chief Accounting Officer and Controller*

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

March 20, 2002	*/s/ Ronald G. Greene* -- *Ronald G. Greene* *Chairman of the Board and Director*
March 20, 2002	*/s/ Gareth Roberts* -- *Gareth Roberts* *Director, President and* *Chief Executive Officer* *(Principal Executive Officer)*
March 20, 2002	*/s/ Phil Rykhoek* -- *Phil Rykhoek* *Chief Financial Officer and Secretary* *(Principal Financial Officer)*
March 20, 2002	*/s/ Mark C. Allen* -- *Mark C. Allen* *Chief Accounting Officer and Controller* *(Principal Accounting Officer)*
March 20, 2002	*/s/ David I. Heather* -- *David I. Heather* *Director*
March 20, 2002	*/s/ Wieland F. Wettstein* -- *Wieland F. Wettstein* *Director*
March 20, 2002	*/s/ David B. Miller* -- *David B. Miller* *Director*

EXHIBIT 13

PAGE 2, PAGES 8 THROUGH 11 INCLUSIVE, PAGES 14 THROUGH 15 INCLUSIVE, PAGES 18 THROUGH 19 INCLUSIVE, PAGES 22 THROUGH 25 INCLUSIVE AND PAGES 28 THROUGH 81 INCLUSIVE, OF THE COMPANY'S ANNUAL REPORT TO SHAREHOLDERS FOR THE YEAR ENDED DECEMBER 31, 2001, BUT EXCLUDING PHOTOGRAPHS AND ILLUSTRATIONS SET FORTH ON THESE PAGES, NONE OF WHICH SUPPLEMENTS THE TEXT AND WHICH ARE NOT OTHERWISE REQUIRED TO BE DISCLOSED IN THIS ANNUAL REPORT ON FORM 10-K.

Financial Highlights

AMOUNTS IN THOUSANDS OF U.S. DOLLARS UNLESS NOTED	YEAR ENDED DECEMBER 31, 2001	2000	1999	1998	1997	AVERAGE ANNUAL GROWTH (2)
PRODUCTION (DAILY)						
Oil (Bbls)	16,978	15,219	12,090	13,603	7,902	21%
Natural Gas (Mcf)	85,238	37,078	27,948	36,605	36,319	24%
BOE (6:1)	31,185	21,399	16,748	19,704	13,955	22%
REVENUES	285,111	181,651	82,990	83,506	86,456	35%
UNIT SALES PRICE (excluding hedges)						
Oil (per Bbl)	21.34	25.89	15.03	10.29	17.25	5%
Natural Gas (per Mcf)	4.12	4.45	2.42	2.31	2.68	11%
UNIT SALES PRICE (including hedges)						
Oil (per Bbl)	21.65	23.50	13.08	10.29	17.25	6%
Natural Gas (per Mcf)	4.66	3.57	2.34	2.32	2.68	15%
CASH FLOW FROM OPERATIONS (1)	186,801	111,555	31,619	30,096	56,607	35%
NET INCOME (LOSS)	56,550	142,227	4,614	(287,145)	14,903	40%
AVERAGE COMMON SHARES OUTSTANDING	49,325	45,823	39,928	25,926	20,224	25%
PER SHARE						
Cash flow from operations (1)						
Basic	3.79	2.43	0.79	1.16	2.80	8%
Diluted	3.71	2.41	0.79	1.15	2.64	9%
Net income (loss)						
Basic	1.15	3.10	0.12	(11.08)	0.74	12%
Diluted	1.12	3.07	0.12	(11.08)	0.70	12%
OIL AND GAS CAPITAL INVESTMENTS	327,175	134,021	54,967	102,652	305,427	2%
CO2 CAPITAL INVESTMENTS	45,555	-	-	-	-	-
TOTAL ASSETS	789,988	457,379	252,566	212,859	447,548	15%
LONG-TERM LIABILITIES	360,882	202,428	154,976	226,436	256,637	9%
STOCKHOLDERS' EQUITY (DEFICIT)	349,168	216,165	72,428	(32,265)	160,223	22%
PROVED RESERVES						
Oil (MBbls)	76,490	70,667	51,832	28,250	52,018	10%
Natural Gas (MMcf)	198,277	100,550	50,438	48,803	77,191	27%
MBOE (6:1)	109,536	87,425	60,238	36,383	64,883	14%
Discounted future cash flow - 10%	574,328	1,158,969	462,870	115,019	361,329	12%
PER BOE DATA (6:1)						
Oil and natural gas revenues	22.88	26.13	14.88	11.36	16.75	8%
Gain (loss) on settlements of derivative contracts	1.64	(3.23)	(1.54)	0.02	-	-
Lease operating costs	(4.84)	(4.94)	(4.25)	(3.49)	(3.54)	8%
Production taxes and marketing expense	(0.96)	(1.02)	(0.60)	(0.56)	(0.82)	4%
Production netback	18.72	16.94	8.49	7.33	12.39	11%
Operating cash flow from CO2 operations	0.38	-	-	-	-	-
General and administrative expense	(0.89)	(1.09)	(1.21)	(1.02)	(1.30)	9%
Net cash interest (expense) income	(1.74)	(1.54)	(2.22)	(2.13)	0.02	-
Current income taxes and other	(0.06)	(0.07)	0.11	-	-	-
CASH FLOW FROM OPERATIONS (1)	16.41	14.24	5.17	4.18	11.11	10%

(1) Exclusive of the net change in non-cash working capital balances.
(2) Four year compounded annual growth rate computed using 1997 as a base year.

Reporting Format

Unless otherwise noted, the disclosures in this report have (i) dollar amounts presented in U.S. dollars, (ii) production volumes expressed on a net revenue interest basis, and (iii) gas volumes converted to equivalent barrels at 6:1.

Selected Operating Data

OIL AND GAS RESERVES

Estimates of our net proved oil and natural gas reserves as of December 31, 2001 and 2000, have been prepared by DeGolyer and MacNaughton, and the estimates as of December 31, 1999 were prepared by Netherland, Sewell and Associates, Inc., both independent petroleum engineers located in Dallas, Texas. The reserves were prepared using constant prices and costs in accordance with the guidelines of the Securities and Exchange Commission ("SEC"), based on the prices received on a field-by-field basis as of December 31 of each year. The reserves do not include any value for probable or possible reserves which may exist, nor do they include any value for undeveloped acreage. The reserve estimates represent our net revenue interest in our properties.

Our proved non-producing reserves primarily relate to additional potential producing zones that are currently behind pipe. Since a majority of our properties are in areas with multiple pay zones, these properties typically have both proved producing and proved non-producing reserves.

Reserves associated with our CO2 operations in West Mississippi and our Heidelberg waterfloods in East Mississippi account for approximately 80% of our proved undeveloped oil reserves. We consider these reserves to be lower risk than other proved undeveloped reserves that require drilling at locations offsetting existing production because there is minimal reservoir risk associated with these reserves since the reservoir has already been defined by drilling of wells during primary production. All of these reserves are associated with secondary recovery and tertiary recovery operations in fields and reservoirs that produced substantial volumes of oil under primary production. The primary reason they are classified as undeveloped is because they require significant additional capital associated with drilling wells and additional facilities in order to produce the reserves. The remaining 20% or our undeveloped oil reserves are located well within the currently producing regions of our fields, many of which are up-dip to existing production.

Our proved undeveloped natural gas reserves are not as concentrated as our oil reserves. The properties we acquired in the Matrix acquisition account for approximately 60% of our proved undeveloped natural gas reserves. These reserves are typically located up-dip to existing wells that ceased producing due to water encroachment. These natural gas reserves are confirmed not only by sub-surface geology but also by 3D seismic that covers these areas. An additional 16% of our proved undeveloped natural gas reserves are located in Heidelberg Field where we continue to have success in-fill drilling the Selma Chalk formation. The remaining significant undeveloped natural gas reserves are in our Thornwell/Lakeside area, primarily associated with the Bol Perc reservoir. We drilled and completed five additional wells there in 2001 without a dry hole. The remaining undeveloped natural gas reserves are again located well within our currently producing reservoirs, many of which are up-dip to existing production. Our current plans for 2002 include development of all of the proved undeveloped natural gas reserves, excluding the offshore reserves. We believe the development of offshore natural gas reserves in a pricing environment of less than $2.50 per Mcf is not warranted and plan to develop these reserves beginning in 2003, assuming prices are above that.

	Year Ended December 31,		
	2001	2000	1999
ESTIMATED PROVED RESERVES:			
Oil (MBbls)	76,490	70,667	51,832
Natural gas (MMcf)	198,277	100,550	50,438
Oil equivalent (MBOE)	109,536	87,425	60,238
PERCENTAGE OF TOTAL MBOE:			
Proved producing	53%	57%	41%
Proved non-producing	23%	18%	25%
Proved undeveloped	24%	25%	34%
REPRESENTATIVE OIL AND GAS PRICES: (1)			
Oil - NYMEX	$ 19.84	$ 26.80	$ 25.60
Natural gas - NYMEX Henry Hub	2.57	9.78	2.12
PRESENT VALUES:(2)			
Discounted estimated future net cash flow before income taxes ("PV10 Value") (thousands)	$ 574,328	$ 1,158,969	$ 462,870
Standardized measure of discounted estimated future net cash flow after income taxes (thousands)	$ 505,795	$ 841,299	$ 448,374

(1) The oil prices as of each respective year-end were based on NYMEX prices per Bbl and NYMEX Henry Hub ("NYMEX") prices per MMBtu, with these representative prices adjusted by field to arrive at the appropriate corporate net price.
(2) Determined based on year-end unescalated prices and costs in accordance with the guidelines of the SEC, discounted at 10% per annum.

FIELD SUMMARIES

Denbury operates in four primary core areas, Louisiana, offshore Gulf of Mexico, Eastern Mississippi and Western Mississippi. Our 13 largest fields constitute approximately 85% of our total proved reserves on a BOE basis and 80% on a PV10 Value basis. Within these 13 fields we own an average 82% working interest and operate all of these fields. The concentration of value in a relatively small number of fields allows us to benefit substantially from any operating cost reductions or production enhancements we achieve and allows us to effectively manage the properties from our three primary field offices in Houma and Covington, Louisiana, and Laurel, Mississippi.

	Proved Reserves as of December 31, 2001 (1)					2001 Average Daily Production		
	Oil (MBbls)	Natural Gas (MMcf)	MMBOE's (000's)	BOE % of Total	PV10 Valu (000's)	Oil (Bbls/d)	Natural Gas (Mcf/d)	Average Net Revenue Interest(2)
Louisiana								
Lirette	348	16,905	3,165	2.9%	33,053	379	13,007	54%
Thornwell	797	11,905	2,781	2.5%	30,330	626	21,895	49%
S.Chauvin	392	11,408	2,293	2.1%	20,526	70	1,426	41%
Other Louisiana	927	23,364	4,822	4.4%	43,027	794	8,064	20%
Total Louisiana	2,464	63,582	13,061	11.9%	126,936	1,869	44,392	38%
Offshore Gulf of Mexico								
W.Delta 27 (3)	1,677	21,676	5,290	4.9%	40,223	264	5,480	56%
South Marsh Island 48 (3)	169	26,294	4,552	4.2%	43,131	21	2,463	83%
Brazos A-22 (3)	104	12,826	2,242	2.0%	12,355	17	1,286	37%
West Cameron 192 (3)	18	8,708	1,469	1.3%	12,216	8	1,976	25%
E. Cameron 33 (3)	36	6,980	1,199	1.1%	12,899	25	4,591	42%
Other offshore	96	23,970	4,090	3.7%	36,244	84	15,841	18%
Total offshore	2,100	100,454	18,842	17.2%	157,068	419	31,637	36%
Eastern Mississippi								
Heidelberg	39,835	26,877	44,315	40.5%	121,381	6,671	7,425	80%
Eucutta	4,460	285	4,508	4.1%	22,315	1,888	116	77%
King Bee	3,108	--	3,108	2.8%	11,524	813	--	82%
Other E. Mississippi	4,667	3,648	5,274	4.8%	24,472	2,682	1,023	48%
Total E. Missisissippi	52,070	30,810	57,205	52.2%	179,692	12,054	8,564	74%
Western Mississippi								
Mallalieu	10,435	--	10,435	9.6%	37,847	57	--	80%
Little Creek	7,562	--	7,562	6.9%	62,042	2,441	--	83%
Other	1,667	--	1,667	1.5%	5,045	62	--	80%
Total W. Missisissippi	19,664	--	19,664	18.0%	104,934	2,560	--	82%
Other	192	3,431	764	0.7%	5,698	76	645	69%
Company Total	76,490	198,277	109,536	100.0%	574,328	16,978	85,238	64%

(1) The reserves were prepared using constant prices and costs in accordance with the guidelines of the SEC based on the prices received on a field-by-fieldbasis as of December 31, 2001. The prices at that date were a NYMEX oil price of $19.84 per Bbl adjusted by field and a NYMEX natural gas price average of $2.57 per MMBtu also adjusted by field.
(2) Only includes wells in which the Company has a working interest as of December 31, 2001.
(3) These fields were acquired during 2001. The average production during the period they were owned by the Company was 14.0 MMcfe/d at W. Delta 27, 5.1 MMcfe/d at S. Marsh Island 48, 2.8 MMcfe/d at Brazos A-22, 4.0 MMcfe/d at W. Cameron 192, and 9.4 MMcfe/d at E. Cameron 33.

Oil and Gas Acreage

The following table sets forth Denbury's acreage position at December 31, 2001:

	Developed		Undeveloped	
	Gross	Net	Gross	Net
Louisiana	21,037	13,563	27,899	16,335
Mississippi	49,892	43,773	60,396	39,538
Offshore Gulf Coast	113,048	56,645	46,716	46,716
Texas	1,890	1,624	19,618	16,610
Total	185,867	115,605	154,629	119,199

Productive Wells

This table sets forth both the gross and net productive wells of the Company at December 31, 2001:

	Producing Oil Wells		Producing Natural Gas Wells		Total	
	Gross	Net	Gross	Net	Gross	Net
Louisiana	23	7.5	71	32.3	94	39.8
Mississippi	369	284.5	61	40.0	430	324.5
Offshore Gulf Coast	4	1.8	86	31.0	90	32.8
Texas	-	-	4	2.8	4	2.8
Total	396	293.8	222	106.1	618	399.9

Drilling Activity

The following table sets forth the results of drilling activities during each of the three fiscal years in the period ended December 31, 2001:

	Year Ended December 31,					
	2001		2000		1999	
	Gross	Net	Gross	Net	Gross	Net
Exploratory Wells: (1)						
Productive (2)	15	8.2	3	1.1	3	1.0
Nonproductive (3)	3	1.2	1	0.2	1	1.0
Development Wells: (1)						
Productive (2)	60	37.9	38	26.5	12	11.9
Nonproductive (3)(4)	-	-	2	0.2	-	-
Total	78	47.3	44	28.0	16	13.9

(1) An exploratory well is a well drilled either in search of a new, as yet undiscovered oil or gas reservoir or to greatly extend the known limits of a previously discovered reservoir. A developmental well is a well drilled within the presently proved productive area of an oil or natural gas reservoir, as indicated by reasonable interpretation of available data, with the objective of completing in that reservoir.
(2) A productive well is an exploratory or development well found to be capable of producing either oil or natural gas in sufficient quantities to justify completion as an oil or natural gas well.
(3) A nonproductive well is an exploratory or development well that is not a producing well.
(4) During 2001, 2000 and 1999, an additional 24, 12 and 4 wells, respectively, were drilled for water or CO_2 injection purposes.

OPERATIONS SECTION OF ANNUAL REPORT

[Map Graphic Omitted]

South Louisiana

Denbury operates on the land and in the marshes of South Louisiana, including state waters. Denbury owns interests in 94 wells and operates 60 of these wells (64%) from its regional office in Houma, Louisiana. This region produces a significant portion of our natural gas, averaging 39.4 MMcf/d net to us in the 4th quarter of 2001, approximately 39% of our total natural gas production. We anticipate future increases in our capital budget for this region as we attempt to increase the percentage of natural gas production Company-wide.

The majority of our onshore fields lie in the Houma embayment area of Terrebonne Parish, including Lirette, Bayou Rambio and South Chauvin Fields. The advent of 3D seismic data in these geologically complex areas has become a valuable tool in exploration and development. We currently own or have a license covering over 550 square miles of 3D data, and plan to expand our data ownership. A portion of this data, the first 3D seismic shot in these swampy areas, was instrumental in our drilling of two successful step- out wells at Lirette in 1999, and one very successful exploration well in 2000. We continued our success in Terrebonne Parish with the drilling of two successful wells in 2001. The first well, Laterre #C-6 (South Chauvin Field), averaged 3.2 MMcf/d and 100 Bbls/d net to the Company during January 2002. The second well, Harry Bourg #4 (Bayou Rambio Field) was drilled very late in 2001 and has just recently been completed. In 2002, we plan to drill three to four additional wells in the Terrebonne Parish area using the same 3D interpretation techniques.

We were very active in Thornwell Field, located in Cameron and Jeff Davis Parishes, during 2001. This field, purchased in late 2000, produced an average of 25.7 MMcfe/d net to our interest during 2001. Our primary interest in purchasing this field was the substantial upside potential that exists in continued development of the existing producing zones (Bol Perc), and the exploration potential of several deeper zones (Marg Howeii and Camerina). These prospects are all defined by a recent 110 square mile 3D seismic survey. During 2001 we were successful in the continued development of the Bol Perc sands, with the drilling of five Bol Perc wells without any dryholes. We also participated in the drilling of one successful Camerina well, SL 15223 #1, which produced 13 MMcfe/d during the fourth quarter of 2001, 2 MMcfe/d net to us. This well appears to have set up at least four additional Camerina prospects in the immediate area. We intend to maintain our level of activity in this area in 2002, with current plans to drill at least three to four Bol Perc wells, two to four Camerina wells and one to two Marg Howeii wells.

Offshore Gulf of Mexico

Denbury's offshore focus is exclusively on the Gulf of Mexico shelf, using the same 3D seismic techniques we have applied onshore. Denbury owns an interest in 90 wells and operates 65 of these wells (72%) from its regional office in Covington, Louisiana. Based on our early success in the Gulf of Mexico, we agreed to purchase Matrix Oil & Gas Inc. in June 2001. Matrix followed our same strategy of acquiring offshore fields from the major oil and gas companies that had produced large quantities of oil and natural gas. We believe large fields that have produced hundreds of millions of barrels of oil and hundreds of billions of cubic feet of natural gas generally have an additional 10% to 15% of additional reserves which can be produced when detailed geology and engineering work is applied. The purchase of Matrix added approximately 42 MMcfe/d to our third and fourth quarter production volumes. By the end of 2001, including Matrix, we drilled, recompleted or sidetracked 12 wells offshore without a dry hole. Offshore production started at near zero at the beginning of 2001 and averaged 55.6 MMcfe/d during the 4th quarter of 2001. Due to the downturn in natural gas prices that occurred late in 2001, we expect to have less activity offshore in 2002 than we did in 2001. Currently we have plans to drill one to three wells offshore during 2002.

We have developed a significant inventory of internal offshore projects as part of the Matrix acquisition. Prior to this acquisition we were focusing on lower risk amplitude plays with expected reserves of 5 to 10 Bcf. Our current inventory of projects has numerous of these projects and after the Matrix acquisition, now includes several prospects with potential in the 50 to 150 Bcf range. The majority of these opportunities will be pursued when, and if, natural gas prices increase.

[Map Graphic Omitted]

[Map Graphic Omitted]

Heidelberg and East Mississippi

In the Eastern part of the Mississippi salt basin, we operate 397 wells out of 430 (92%) from our office in Laurel, Mississippi. These fields produced an average of 11,434 Bbls/d and 8.2 MMcf/d during the 4th quarter of 2001. The largest field in the region, and our largest field, is Heidelberg Field, which for the fourth quarter of 2001 produced an average of 7,814 BOE/d. We have been active in this area since Denbury was founded in 1990 and are by far the largest producer in the basin.

Our strategy has been to increase reserves and production in and around existing fields. The fields in this region are characterized by structural traps that generate prolific production from stacked or multiple pay sands. As such, they provide opportunities to increase reserves through infield drilling, recompletions, improvements in production efficiency, and in some cases, by water flooding producing reservoirs. Most of our wells produce large amounts of saltwater and require large pumps, which increases the operating costs per barrel relative to our properties in Louisiana that are predominantly natural gas producers. We plan to continue our basic strategy in the region, supplemented by additional waterflooding (secondary recovery) and eventually carbon dioxide ("CO2") flooding (tertiary recovery).

Our primary interests at Heidelberg Field were acquired from Chevron in December 1997. This field was discovered in 1944 and has produced an estimated 196 MMBbls of oil and 39 Bcf of gas since its discovery. The Field is a large salt-cored anticline that is divided into western and eastern segments due to subsequent faulting. Production is from a series of normally pressured Cretaceous and Jurassic Age sandstone formations situated between 3,500 feet and 11,500 feet. There are 11 producing formations in the Heidelberg Field containing 40 individual reservoirs, with the majority of the past and current production coming from the Eutaw and Christmas sands at depths of 4,000 to 5,000 feet.

We continue to employ the latest technological advances in artificial lift, open-hole and cased-hole logging techniques, and most recently, hydraulic fracturing techniques. When we acquired the property, production was approximately 2,800 BOE/d. As a result of our subsequent development work, production for 1998 averaged 3,760 BOE/d, for 1999 averaged 5,708 BOE/d, for 2000 averaged 7,310 BOE/d and for 2001 averaged 7,908 BOE/d.

We currently operate five waterflood units at Heidelberg: four on the east side and one expanded unit on the west. These waterflood units produce from the shallow (approximately 4,400 feet) Eutaw formation. The cumulative production from these five units since their initial discovery is estimated at 73.5 million barrels, or approximately 25% of the original oil estimated to be in place. We believe that properly designed and executed waterflood programs should increase the recovery factor to 40%, similar to our expectations from the nearby analogous Eucutta Field.

During 2001, we continued our development of the Selma Chalk formation in Heidelberg, which produces natural gas at a depth of 3,700 feet. Previous operators only partially developed this formation in order to provide fuel gas for the rest of the field. We drilled 13 wells in 2001 that effectively reduced the well spacing down to 40 acres in East Heidelberg. Using modern hydraulic fracturing techniques, we increased the natural gas production at Heidelberg to over 10 MMcf/d. We believe that there may be opportunities to extend this plan and further reduce the well spacing. However, this will probably be delayed until natural gas prices recover.

We believe that there may also be additional potential in several zones below the Eutaw formation, including the Christmas, Tuscaloosa, Paluxy, Rodessa, Hosston, and Cotton Valley formations. These formations have produced a combined 81 MMBbls and 20 Bcf from inception through late 2001.

Denbury has pursued the same strategy at its other significant fields in East Mississippi; Eucutta, Quitman, Davis, Sandersville and King Bee Fields. After we acquired each of these oil fields, we initiated a rework program to increase production and reserves. Davis Field, one of our oldest fields, is an example of our strategy in Mississippi. This field was producing approximately 600 Bbls/d and had reserves of approximately 1.8 MMBbls when we acquired it in 1993. Since then, the field has produced at various rates, with a monthly high of approximately 1,700 Bbls/d, and a fourth quarter 2001 average rate of 538 Bbls/d. Over the eight years since its acquisition, we have produced in excess of 2.0 MMBbls of oil.

We have just completed the first 3D seismic survey ever shot over King Bee Field (Cypress Creek Dome), a field we acquired from Fina in 1999. King Bee Field is a salt dome field with relatively few wells drilled over the years, since it underlies a national forest and a US Military bombing range. Due to these surface restrictions, wells have to be drilled from sites outside of the bombing area, and thus well costs are higher than normal. The higher costs of drilling and the steeply dipping beds of the producing formations make it imperative to have a very good geologic picture of the subsurface prior to drilling. Fina and prior operators attempted to drill wells here based on a few scattered 2D seismic lines with mixed success.

Several relatively large accumulations of oil (5 to 12 MMBbls) have been found around Cypress Creek Dome with a large portion of the eastern flank being untested. We own this proprietary 3D seismic survey and have high expectations for reserve additions in the coming years. Since we acquired this field, production has increased slightly through only a minor amount of capital expenditures. Our 2002 plans include the drilling of one well to begin pressure maintenance operations in a Lower Tuscaloosa fault block that we believe could contain up to 11 MMBbls of oil in place. This fault block produced an average of 800 Bbls/d from two wells during 2001.

[Map Graphic Omitted]

West Mississippi and our CO_2 Assets

Denbury began its activities in this part of the basin in September 1999 with the purchase of Little Creek Field, now our 2nd largest field based on PV10 values at December 31, 2001. In February 2001, we acquired CO_2 reserves and producing wells near Jackson, Mississippi, which included a 183-mile pipeline that transports CO_2 to Little Creek Field in the southwestern part of the state. This acquisition allowed us to expand our tertiary CO_2 gas flooding at Little Creek Field Unit into West Little Creek Field and Lazy Creek Field Unit, as well as begin CO_2 flooding at West Mallalieu Field Unit, a field we acquired in May 2001.

Carbon dioxide injection for tertiary recovery purposes has been used extensively in the Permian Basin Region of West Texas, because of the availability of large reserves of CO_2. Carbon dioxide injection is one of the most efficient tertiary recovery mechanism for crude oil, but its application is limited by the availability of large quantities of CO_2, which had been restricted to West Texas, Mississippi and other isolated areas. The carbon dioxide acts as a type of solvent for the oil, removing it from the formation as the CO_2 is produced. For example, in a typical oil field, between 40% and 50% of the oil in place can be extracted by primary and secondary (waterflooding) recovery. An additional amount of oil (17% at Little Creek) can be recovered by injecting CO_2 into certain wells and then recovering oil and CO_2 from other wells.

In Mississippi, CO_2 reserves have been discovered around Jackson dome, a volcanic intrusive which was emplaced about 80 million years ago. The CO_2 reserves in this area are found in structural traps in the Buckner, Smackover and Norphlet formations at depths of about 15,000 feet. Some estimates have suggested that there are 12 Tcf of usable CO_2 in this area. Our acquisition included 10 producing CO_2 wells, which were originally drilled by Shell to supply CO_2 to Little Creek Field, with an estimated 815 Bcf of proved producing CO_2 reserves. During the fourth quarter of 2001, we sold an average of 41 MMcf/d to commercial users and we used an average of 52 MMcf/d for our tertiary activities.

The western part of Mississippi has produced over 245 MMBbls of light sweet crude oil from Tuscaloosa sandstones at a depth of about 10,000 feet. The application of a theoretical recovery factor of 17% of original oil in place suggests that about 80-100 MMBbls of additional reserves may be available in fields in this part of the state.

Obviously, a great deal of work is required before these reserves can be recorded as proved reserves, such as acquiring properties, leasing, reworking and reentering wells and installing production facilities; however, preliminary indications suggest that there is considerable potential for us in this part of Mississippi.

As of March 15, 2002, we currently have leased or own eight fields in this area with the potential of 20 to 35 MMBbls of additional reserves, beyond our current proved reserves of 19.7 MMBbls, based on the 17% recovery factor that we have at Little Creek Field. Our total acquisition cost to date for these additional fields is approximately $2.4 million. Since most of these fields in the area are depleted or nearly depleted, the acquisition cost is minimal. We will continue to pursue additional acquisitions in the area around our pipeline to use in our tertiary recovery operations.

[Map Graphic Omitted]

Little Creek and Mallalieu Field

Little Creek Field was discovered in 1958, and by 1962 the field had been unitized and waterflooding had commenced. The pilot phase of CO_2 flooding began in 1974 and the first two phases (which are merely distinct areas of the field) of the field began in 1985. When we acquired the field in 1999, these first two phases were substantially complete and Phase III was in process. We have completed Phase III and Phase IV and initiated CO_2 injection into Phase V. Our plans in 2002 are to finish Phase V and further expand into areas beyond the original patterned areas in Phases III, IV and V. Currently there are 44 producing wells and 29 injection wells at Little Creek. Based on the results of the two earliest phases of CO_2 flooding at Little Creek, tertiary recovery has increased the ultimate recovery factor in that portion of the field by approximately 17%, as compared to approximately 20% for primary recovery and 18% for secondary recovery. The field has produced a cumulative 57.8 MMBbls of light sweet crude and we currently estimate that an additional 9.5 MMBbls will be recovered.

Production from Little Creek Field was approximately 1,350 Bbls/d when we acquired it in 1999. During the fourth quarter of 2001, production had increased to an average of 3,052 BOE/d, up from 2,206 BOE/d in the fourth quarter of 2000. We expect the production from Little Creek to increase throughout 2002 and peak during 2003 at an estimated net rate of 4,500 to 5,000 BOE/d.

We expanded our CO_2 flooding operations following our purchase of the CO_2 source field. During 2001 we formed two additional units offsetting Little Creek Field: West Little Creek Field Unit and Lazy Creek Field Unit. These areas were previously developed and abandoned following primary production. These two units can be CO_2 flooded with the existing infrastructure at Little Creek, and thus the cost for facilities will be dramatically reduced. During January 2002, the West Little Creek Unit began responding to CO_2 injection and was producing approximately 425 Bbls/d. The Lazy Creek Unit had not responded as of January, 2002.

In addition to our expansion activities at Little Creek, we purchased West Mallalieu Field Unit for $4.0 million in May 2001. West Mallalieu Field Unit was originally unitized by Shell Oil Company, and a subsequent pilot project was commenced in 1986. The pilot project, consisting of four 5-spot patterns, produced approximately 2.1 MMBbls of oil as a result of CO_2 flooding. We expanded the pilot project by adding an additional four patterns during

2001 and expect response to occur during the latter part of 2002. In contrast to Little Creek Field, West Mallalieu Field was not waterflooded prior to CO_2 injection. Therefore, the tertiary recovery of oil from West Mallalieu Field Unit as a result of CO_2 injection could exceed the 17% of original oil in place that is expected from Little Creek Field.

At December 31, 2001, we had proved reserves of 10.4 MMBOE at Mallalieu, for an acquisition cost of less than $0.40 per BOE. This field's future development costs are between $3.00 and $4.00 per BOE, which we believe is typical for fields in this area. With all-in finding and development costs of approximately $4.00 per BOE and anticipated operating costs of around $10.00 per BOE, these tertiary recovery operations in West Mississippi along our pipeline are very profitable at $18 to $20 oil prices, as they produce light sweet oil that receives near NYMEX pricing. Through December 31, 2001, we had spent a total of $51.8 million on fields in this area, primarily Little Creek and Mallalieu Field, have received $28.7 million in net operating income, leaving us a balance of $23.1 million to recover for payout. This compares to a PV10 value, using December 31, 2001 SEC pricing of $19.84 per Bbl, of $104.9 million.

Barnett Shale

Denbury also owns about 20,000 acres of leases in the Fort Worth Basin which is prospective for the Barnett Shale. Five wells have been drilled in 2001, two of which were producing at year end and three others were awaiting completion. The Company plans to drill a minimal number of wells in this play until gas prices recover to above $3.00 per Mcf.

Selected Abbreviations

Bbl	One stock tank barrel, of 42 U.S. gallons liquid volume, used herein in reference to crude oil or other liquid hydrocarbons.
Bbls/d	Barrels of oil produced per day.
Bcf	One billion cubic feet of natural gas.
BOE	One barrel of oil equivalent using the ratio of one barrel of crude oil, condensate or natural gas liquids to 6 Mcf of natural gas.
BOE/d	BOEs produced per day.
Btu	British thermal unit, which is the heat required to raise the temperature of a one-pound mass of water from 58.5 to 59.5 degrees Fahrenheit.
MBbls	One thousand barrels of crude oil or other liquid hydrocarbons.
MBOE	One thousand BOEs.
MBtu	One thousand Btus.
Mcf	One thousand cubic feet of natural gas.
Mcf/d	One thousand cubic feet of natural gas produced per day.
MMBbls	One million barrels of crude oil or other liquid hydrocarbons.
MMBOE	One million BOEs.
MMBtu	One million Btus.
MMcf	One million cubic feet of natural gas.
PV10 Value	When used with respect to oil and natural gas reserves, PV10 Value means the estimated future gross revenue to be generated from the production of proved reserves, net of estimated production and future development costs, using prices and costs in effect at the determination date, before income taxes, and without giving effect to non-property-related expenses, discounted to a present value using an annual discount rate of 10% in accordance with the guidelines of the Securities and Exchange Commission.
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 crude oil, natural gas and natural gas liquids which geological and engineering data demonstrate with reasonable certainty to be 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.
Tcf	One trillion cubic feet of natural gas.

We are a growing independent oil and gas company engaged in acquisition, development and exploration activities in the U.S. Gulf Coast region. We are the largest oil and natural gas producer in Mississippi, hold key operating acreage onshore Louisiana and have a growing presence in the offshore Gulf of Mexico areas. Our goal is to increase the value of acquired properties through a combination of exploitation, drilling, and proven engineering extraction processes. Our corporate headquarters are in Dallas, Texas, and we have three primary field offices located in Houma and Covington, Louisiana, and Laurel, Mississippi.

2001 ACQUISITIONS

Carbon Dioxide Acquisition

In February 2001, we acquired carbon dioxide ("CO2") reserves, production and associated assets from a unit of Airgas, Inc., for $42.0 million. This acquisition included ten producing CO2 wells and production facilities located near Jackson, Mississippi, and a 183-mile, 20-inch pipeline that is currently transporting CO2 to our tertiary recovery operations at Little Creek Field, a field we purchased in August 1999, and Mallalieu Field, a field we purchased in May 2001, as well as to other commercial users. We acquired nearly 100% of the working interest in the producing CO2 wells and we operate the properties. As of December 31, 2001, based on a report prepared by DeGolyer and MacNaughton, we believe that these wells have approximately 815 billion cubic feet of usable CO2 reserves, net to our working interest.

Our CO2 production has increased gradually since we acquired the property. We have increased the CO2 that we use in our operations due to further expansion of the tertiary recovery project at Little Creek Field and initiation of a new tertiary recovery project at Mallalieu Field late in 2001. Our sales to our industrial customers also increased slightly throughout the year. During the fourth quarter of 2001, CO2 production averaged approximately 92.9 million cubic feet of CO2 per day, of which about 51.6 million cubic feet per day was used for injection at our two tertiary recovery operations, with the remainder of about 41.3 million cubic feet per day sold under long-term contracts to commercial CO2 users.

We estimate that the CO2 production capacity of the acquired wells is approximately 110 million cubic feet of CO2 per day, but believe that production could be increased to about 250 million cubic feet of CO2 per day by adding compression facilities. An associated pipeline purchased in the acquisition is capable of transporting over 700 million cubic feet of CO2 per day with additional facilities and increased compression. We plan to continue to expand our CO2 operations through acquisitions of additional oil fields, particularly along our pipeline, and implementing new tertiary floods there for the next several years, as our ownership of the CO2 source wells, pipeline and facilities assures us that CO2 will be available to us when we need it at a reasonable and predictable cost. We anticipate that we will spend between 25% and 50% of our annual development budget on these projects, at least for the next few years, unless there is a significant drop in oil prices or our economics change for some unforeseen reason. In addition to the oil fields near our pipeline that we can potentially acquire and flood, there is also the potential to expand our pipeline farther south in Louisiana or east in Mississippi, where we believe there are other potential tertiary recovery projects. We believe that the ownership of these CO2 reserves provides us a significant strategic advantage in the acquisition of other properties in Mississippi and Louisiana that could be further exploited through tertiary recovery.

Matrix Acquisition

On July 10, 2001, we acquired Matrix Oil & Gas, Inc., an independent oil and gas company based in Covington, Louisiana. The primary reasons for the acquisition were (i) that the assets, older complex fields that have produced significant amounts of oil and natural gas, appear to have significant potential incremental reserves, and (ii) that the acquisition increased our natural gas production, bringing our oil and natural gas production ratio to approximately 50/50. Most of the Matrix properties and activities are in the offshore Gulf of Mexico, with an interest in 19 offshore blocks and two onshore fields. At June 30, 2001, based on a reserve report prepared by DeGolyer and MacNaughton, Matrix had estimated proved reserves of 11.9 MMBOE (71.6 Bcfe), 92% of which was natural gas and 78% of which was proved developed. By year-end, based on DeGolyer and MacNaughton's reserve report, we had increased their reserves 35% to 16.1 MMBOE (96.6 Bcfe), or a 46% increase when you adjust for the production from July to December, 2001. These reserve additions (32.7 Bcfe) came from the $24.6 million invested in development and exploration projects on these properties since they were acquired in July.

In our acquisition of Matrix we paid approximately $158.5 million, comprised of $99.3 million (63%) in cash and $59.2 million (37%) in the form of 6.6 million shares of our common stock. We funded the cash portion of the purchase price with available cash and $95.0 million drawn under our bank credit facility. At the time of the acquisition, we recorded $30.0 million of the purchase price as unevaluated property costs to reflect the significant probable and possible reserves that we had identified. At year-end, we reduced our unevaluated property costs by $5.0 million based on the results of our drilling activity and the reserves added since the acquisition. We believe that there are significant additional potential reserves on these properties.

As with other recent acquisitions, we purchased commodity hedges to protect our investment when we acquired Matrix. These hedges, in the form of price floors, covered nearly all of the forecasted production from the acquired properties for two and one-half years through the end of 2003 at floor prices ranging from $3.75 to $4.25 per MMBtu. Due to the falling natural gas prices in the latter half of 2001, we collected approximately $12.7 million on these hedges in 2001. Unfortunately, the price floors relating to 2002 and 2003 were purchased from Enron Corporation, which filed bankruptcy in December 2001. We sold our bankruptcy claim against Enron in February 2002, which included the claim for the price floors and minor natural gas production receivables, collecting net proceeds of approximately $9.2 million. In total, we collected approximately $21.9 million from our price floors relating to the Matrix acquisition, a net cash gain of approximately $3.9 million over the cost of the floors, but have suffered an opportunity loss in light of the drop in natural gas prices since the date of the Matrix acquisition and the loss of our 2002 and 2003 hedges. Since the Enron bankruptcy we have purchased additional hedges to protect against any further deterioration in natural gas prices. See "Market Risk Management" below for further information regarding these hedges and the accounting treatment related to the former Enron hedges.

CAPITAL RESOURCES AND LIQUIDITY

ELEMENTS OF INCREASED CASH FLOW AND PRE-TAX EARNINGS IN 2001. We had record pre-tax earnings and cash flow from operations in 2001 primarily because of our 46% increase in average daily production and near record average commodity prices. We generated $186.8 million in cash flow from operations (excluding the net change in non-cash working capital balances), 67% higher than our prior high in 2000. You may find more details about these items in the section "Results of Operations" below.

INCREASED PRODUCTION. Our production increased approximately 46% between 2000 and 2001. The most significant factor in this increase was the purchase of Matrix in early July 2001. This acquisition added 3,524 BOE/d, primarily natural gas, to our average 2001 production, representing approximately 36% of the increase. The remainder of the increase came from our development and exploitation projects on existing fields and other smaller acquisitions.

COMMODITY PRICES. NYMEX oil prices were at historic lows in the $12.00 per Bbl range at year-end 1998, but increased steadily during the next two years to an average of approximately $30.25 per Bbl during 2000. During 2001, NYMEX oil prices declined to an average of $26.00 (as compared to a net corporate average price received of $21.34 per Bbl for 2001 before the positive impact of hedging).

Graph depicting the NYMEX crude oil price listings by month from January 1999 through December 2001:

Jan-99	Feb-99	Mar-99	Apr-99	May-99	Jun-99	Jul-99	Aug-99	Sep-99	Oct-99	Nov-99	Dec-99
12.49	12.02	14.68	17.30	17.77	17.92	20.10	21.28	23.79	22.67	24.77	26.09
Jan-00	Feb-00	Mar-00	Apr-00	May-00	Jun-00	Jul-00	Aug-00	Sep-00	Oct-00	Nov-00	Dec-00
26.88	29.37	30.06	25.64	28.95	31.46	30.05	31.17	33.76	32.90	34.40	28.35
Jan-01	Feb-01	Mar-01	Apr-01	May-01	Jun-01	Jul-01	Aug-01	Sep-01	Oct-01	Nov-01	Dec-01
29.32	29.76	27.29	27.63	28.70	27.62	26.57	27.31	26.45	22.21	19.67	19.46

Natural gas prices increased dramatically during 2000 and early 2001, from a NYMEX price of approximately $2.35 per Mcf at year-end 1999, to an average price of approximately $3.90 per Mcf for 2000, and an average of $4.26 in 2001 (as compared to a net corporate average price received of $4.12 per Mcf for 2001 before the positive impact of hedging). The biggest fluctuation in natural gas prices during the three year period was in late 2000 and early 2001 when natural gas prices were around $10.00 per Mcf for a brief period of time. Throughout the remainder of 2001 they declined, dropping to a December 31, 2001 year-end price of $2.57 per Mcf. On a price per BOE basis (before the impact of hedges), our average commodity prices dropped 12% in 2001 from 2000 levels.

Graph depicting the NYMEX natural gas price listings by month from January 1999 through December 2001:

Jan-99	Feb-99	Mar-99	Apr-99	May-99	Jun-99	Jul-99	Aug-99	Sep-99	Oct-99	Nov-99	Dec-99
1.80	1.81	1.64	1.88	2.35	2.23	2.28	2.62	2.90	2.55	3.06	2.14
Jan-00	Feb-00	Mar-00	Apr-00	May-00	Jun-00	Jul-00	Aug-00	Sep-00	Oct-00	Nov-00	Dec-00
2.36	2.61	2.61	2.88	3.08	4.37	4.36	3.83	4.62	5.29	4.50	6.02
Jan-01	Feb-01	Mar-01	Apr-01	May-01	Jun-01	Jul-01	Aug-01	Sep-01	Oct-01	Nov-01	Dec-01
9.91	6.22	5.03	5.35	4.87	3.73	3.16	3.19	2.34	1.86	3.16	2.28

DEBT. Our total debt level increased from $199.0 million as of December 31, 2000 to $340.9 million (excluding the unamortized issue discount) as of December 31, 2001, primarily as a result of the debt incurred to fund the Matrix and CO_2 acquisitions, as our other capital spending was funded with cash flow from operations. The cash portion of the Matrix acquisition was approximately $100 million and the CO_2 acquisition cost us about $42 million.

During August 2001, we issued an additional $75 million of subordinated debt in a private placement at 91.371% of face amount, for an effective yield of 10.875%. The notes were issued under a separate indenture but on terms substantially identical to our existing 9% Senior Subordinated Notes due 2008. We used the net proceeds of $65.9 million to reduce our existing bank debt. These notes were subsequently exchanged for a like principal amount of publically registered notes.

The remaining debt increase during 2001 was bank debt. As of December 31, 2001, we owed the banks approximately $141 million, with a borrowing base of $220 million. This compares to total bank debt of $74 million a year earlier with a $150 million borrowing base. In summary, we had approximately the same availability under our bank credit line at year-end 2001 as we did a year ago. The increase in the borrowing base in 2001 was a result of the increase in our proved reserves throughout the year, particularly from the acquired Matrix properties, partially offset by the higher subordinated debt outstanding.

Our bank credit facility provides for a semi-annual redetermination of our borrowing base on April 1st and October 1st. In keeping with our fiscal policy during the last three years, we plan to reserve our credit line primarily for potential acquisitions. Our next scheduled borrowing base redetermination will be as of April 1, 2002. We do not anticipate any significant change in our borrowing base, although the borrowing base can always be reduced at the banks' discretion, which can be based in part upon external factors over which we have no control.

Graph depicting the Company's debt to total capitalization (in millions of dollars):

	December 31,			
	1998	1999	2000	2001
Debt	225.0	152.5	199.0	334.8
Total Capitalization	192.7	224.9	415.2	683.9

CAPITAL SPENDING AND RESOURCES. Our leverage at year-end 2001, as measured on a debt to cash flow basis, was almost the same as a year earlier. At December 31, 2001, our total debt was $340.9 million (excluding the unamortized issue discount), approximately 1.8 times our 2001 cash flow from operations (before the change in other assets and liabilities), essentially the same as the prior year-end computed on the same basis. However, we were in a rising commodity price environment at the end of 2000 and just the opposite at the end of 2001, which means that this debt ratio is likely to increase during 2002. Both oil and natural gas prices were at long-term average prices as of the end of 2001, continued to fall during the first month or two of 2002, but were back above year-end levels by early March 2002.

With the reduced commodity prices, our debt level has risen to around three times our anticipated 2002 cash flow based on futures prices as of early March 2002. While this projected debt to cash flow ratio is higher than it was in 2001, in our opinion it is not high when compared to our peer group, and we do not anticipate any problems in the foreseeable future with our debt levels or liquidity. During the last few years, we have had wide swings in commodity prices, in response to which we adjust our spending and plans accordingly and attempt to mitigate some of the price dips with our hedging program. To help protect our balance sheet in this most recent drop in commodity prices, we have taken the following steps consistent with our corporate strategy:

1) We purchased additional natural gas hedges for 2002 after the Enron bankruptcy that cover approximately 75% of our forecasted natural gas production, with a price floor of $2.50 per MMBtu. We also have oil hedges in place that cover approximately 60% of our forecasted 2002 oil production, with a price floor of $21.00 per Bbl. Therefore, even though prices have continued to deteriorate during the first part of 2002 and both commodities have dropped, at least a portion of the time below our price floors, the effect of such drops on us is limited to the unhedged portion of our production. With our balanced production mix of oil and natural gas, we also have a type of natural hedge in that the two commodity prices do not always move in tandem.

2) Our original capital budget for 2002 was approximately $120 million. With the loss of the Enron hedges, we immediately lowered our budget to approximately $95 million to compensate for the loss of expected revenue from these hedges. While this capital budget could be slightly higher than our anticipated cash flow for 2002, depending on the price forecast that is used, when coupled with the $9.2 million that we received in February 2002 by selling our claim against Enron, we will have the ability to complete our 2002 development and exploration plan without incurring significant additional debt. This is consistent with our strategy in recent years to generally attempt to match our anticipated cash flow with our capital spending program (excluding acquisitions). We will also review our 2002 budget on a quarterly basis and make adjustments if necessary.

3) For the last three years we have reserved our bank credit line for acquisitions. We plan to continue this strategy. As of March 15, 2002, we had approximately $74 million available on our credit line. While this amount could be adjusted at the April 1st redetermination, we do not expect our borrowing base to change materially, if at all. We continue to pursue acquisitions which, if accomplished, should be accretive to our operating results. We cannot be certain that we will identify any suitable acquisitions in the future or that any such acquisitions will be successful in achieving our desired profitability objectives. We have a significant inventory of development and exploration projects in-house, but on a long-term basis we will need further acquisitions to replace our production. We may also consider the sale of some of our more mature properties from time to time with the intention of replacing them with properties that we can further exploit.

Graph depicting development and exploration expenditures vs. cash flow from operations (in millions of dollars):

	Year Ended December 31,		
	1999	2000	2001
Development and exploration expenditures	$ 34.5	$ 73.7	$ 170.1
Cash flow from operations (1)	31.6	111.6	186.8

(1)Excluding the net change in non-cash working capital balances.

Our capital budget for 2002, excluding acquisitions, is currently set at $95 million. Approximately 25% of the projected 2002 expenditures are targeted for our East Mississippi properties (primarily Heidelberg Field), 25% for Little Creek and Mallalieu Fields and other CO_2 floods, 25% for the recently acquired Thornwell Field and other fields in onshore Louisiana, 10% for offshore activities, and the balance for various other fields, capitalized overhead, land, seismic, and discretionary expenditures. Of the total budget, approximately 12% is related to exploratory drilling, seismic or other exploratory expenditures. We will continue to review our budget each quarter and make adjustments for changes in commodity prices, oilfield service and equipment costs, and our drilling results. With the recent decline in commodity prices, we are experiencing some declines in oilfield service and equipment costs, which may allow us to undertake more projects than we originally anticipated for the same dollars. In contrast, during 2000 and 2001, we were faced with rising oilfield service and equipment costs which required us to increase our budget several times solely for cost inflation.

At our current capital spending level and the current level of commodity prices, we expect our production to average approximately 35,250 BOE/d in 2002, a 13% increase over our 2001 average, but only a slight increase over the rate of production during the fourth quarter of 2001. For 2002, 15% to 20% of our capital expenditures are allocated to new tertiary recovery operations that are not expected to respond until late 2002. We believe that the balance of our capital expenditures of $75 million to $80 million is sufficient to generate modest production growth throughout the year.

We have no significant off balance sheet arrangement, special purpose entities, financing partnerships or guarantees, nor any debt or equity triggers based upon our stock or commodity prices. Our bank debt is not due until December 31, 2003, a date we expect to extend, and our subordinated debt is due in March 2008. Our only other obligations that are not currently recorded on our balance sheet are our operating leases, which primarily relate to our office space and minor equipment leases, and various spending obligations for development and exploratory expenditures arising from purchase agreements or other transactions common to our industry. Our operating lease obligations total $12.5 million in the aggregate and $1.7 million for 2002. Our capital spending obligations total approximately $13.6 million over the next four years, none of which is required in 2002. As is common in our industry, we commit to make certain expenditures on a regular basis as part of our ongoing development and exploration program. These commitments generally relate to projects that will occur during the subsequent six months and are part of our annual budget process. We also have an obligation to deliver approximately 90 Bcf of CO_2 to our industrial customers. Based on the size of our proven CO_2 reserves and our current production capabilities, we are confident we can meet these delivery obligations. At December 31, 2001, we had a total of $370,000 outstanding in letters of credit. We do not have any material transactions with related parties.

Graph depicting capital expenditures (in millions of dollars):

	Year Ended December 31, 1999	2000	2001
Acquisitions	$ 20.5	$ 60.3	$ 157.1
Development and exploration expenditures	34.5	73.7	170.1

SOURCES AND USES OF FUNDS. During 2001, we spent approximately $170.1 million on exploration and development activities and approximately $157.1 million on acquisitions (excluding the $42 million CO_2 acquisition), the largest being the acquisition of Matrix. Our exploration and development expenditures included approximately $115.9 million spent on drilling, $18.7 million of geological, geophysical and acreage expenditures and $35.5 million spent on facilities and recompletion costs. The exploration and development expenditures were funded by cash flow from operations, and the acquisitions were primarily funded by net incremental debt.

During 2000, we spent approximately $73.7 million on exploration and development activities and approximately $60.3 million on acquisitions. These exploration and development expenditures included approximately $37.8 million spent on drilling, $8.5 million of geological, geophysical and acreage expenditures and $27.4 million spent on facilities and recompletion costs. We funded these exploration and development expenditures with cash flow from operations and funded our acquisitions with cash flow and net incremental bank debt of $46.5 million.

During 1999, we spent approximately $34.5 million on exploration and development activities and approximately $20.5 million on acquisitions. Our exploration and development expenditures included approximately $8.6 million spent on drilling, $5.7 million of geological, geophysical and acreage expenditures and $20.2 million spent on facilities and recompletion costs. These exploration and development expenditures were funded primarily by our cash flow from operations and the acquisitions were funded with both cash flow and incremental bank debt of $17.9 million.

RESULTS OF OPERATIONS

Operating Income

Cash flow from operations has improved each year since 1998 because of the improved commodity prices and higher production levels. Net income has generally tracked cash flow if you adjust for certain non- recurring entries that affect the bottom line, such as the reversal of the valuation allowance on our deferred tax assets in 2000 and the write-off of the Enron hedges in 2001. Each of these factors is more fully described below.

	Year Ended December 31,		
Amounts in Thousands Except Per Share Amounts	2001	2000	1999
Net income	$ 56,550	$ 142,227	$ 4,614
Net income per common share:			
Basic	$ 1.15	$ 3.10	$ 0.12
Diluted	1.12	3.07	0.12
Cash flow from operations (1)	$ 186,801	$ 111,555	$ 31,619

(1) Represents cash flow provided by operations, exclusive of the net change in non-cash working capital balances.

Graph depicting cash flow from operations, excluding the net change in non-cash working capital balances, by quarter (in millions of dollars):

	1999				2000				2001		
Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4
$2.5	$6.6	$9.5	$13.0	$19.6	$21.3	$27.5	$43.2	$55.0	$45.2	$48.7	$37.9

During 2001, we set company records for production, revenue, cash flow and pre-tax net income. Certain of our operating statistics are set forth in the following chart.

	Year Ended December 31,		
	2001	2000	1999
AVERAGE DAILY PRODUCTION VOLUME			
Bbls	16,978	15,219	12,090
Mcf	85,238	37,078	27,948
BOE(1)	31,185	21,399	16,748
OPERATING REVENUES AND EXPENSES (THOUSANDS)			
Oil sales	$ 132,219	$ 144,230	$ 66,330
Natural gas sales	128,179	60,406	24,661
Gain (loss) on settlements of derivative contracts (2)	18,654	(25,264)	(9,416)
Total oil and natural gas revenues	279,052	179,372	81,575
Lease operating costs	55,049	38,676	26,029
Production taxes and marketing expenses	10,963	8,051	3,662
Total production expenses	66,012	46,727	29,691
Production netback	$ 213,040	$ 132,645	$ 51,884
UNIT PRICES-INCLUDING IMPACT OF HEDGES(2)			
Oil price per Bbl	$ 21.65	$ 23.50	$ 13.08
Gas price per Mcf	4.66	3.57	2.34
UNIT PRICES-EXCLUDING IMPACT OF HEDGES(2)			
Oil price per Bbl	21.34	25.89	15.03
Gas price per Mcf	4.12	4.45	2.42
NETBACK PER BOE (1)			
Oil and natural gas revenues	$ 24.52	$ 22.90	$ 13.34
Lease operating costs	4.84	4.94	4.25
Production taxes and marketing expenses	0.96	1.02	0.60
Total production expenses	$ 5.80	$ 5.96	$ 4.85

(1) Barrel of oil equivalent using the ratio of one barrel of oil to six Mcf of natural gas ("BOE").
(2) See also "Market Risk Management" below for information concerning the Company's hedging transactions.

Production. From the first quarter of 1999 through the third quarter of 2001, our average daily production increased each quarter, with production in the fourth quarter of 2001 being only slightly less than our third quarter peak. Prior to 1999, we had severely curtailed our development and exploration program due to the historically low oil prices in 1998. As oil prices began to gradually increase in early 1999, we correspondingly resumed our development program. The production increases since that time have resulted from a combination of acquisitions, development, exploration and exploitation activities. From time to time, we have also experienced significant production increases from our waterflood and tertiary recovery operations. These production responses generally do not correspond directly with our related capital spending, as it typically takes six to twelve months to see any production response after the injection of water or carbon dioxide begins.

Graph depicting production by quarter (average MBOE per day):

	1999				2000				2001			
	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4
Oil	10.3	11.5	12.5	14.0	14.4	14.8	15.4	16.3	16.3	16.4	16.9	18.3
Natural Gas	5.1	4.5	4.5	4.5	4.7	4.8	5.1	10.0	10.3	11.5	18.2	16.7
Total	15.4	16.0	17.0	18.5	19.1	19.6	20.5	26.3	26.6	27.9	35.1	35.0

Since our December 1997 $202 million acquisition of Heidelberg Field from Chevron, our significant acquisitions of oil and natural gas properties have been the $4.9 million acquisition of King Bee Field in May 1999, the $12.3 million acquisition of Little Creek Field in August 1999, the $56.5 million acquisitions of Thornwell, Porte Barre and Iberia Fields in the fourth quarter of 2000, the $4.0 million acquisition of Mallalieu Field in May 2001 and the $158.5 million corporate acquisition of Matrix in July 2001 (see "Matrix Acquisition" above).

At the time of its acquisition in December 1997, Heidelberg Field was producing approximately 2,800 BOE/d. Production under our ownership has subsequently averaged 3,760 BOE/d, 5,708 BOE/d, 7,310 BOE/d, and 7,908 BOE/d for 1998, 1999, 2000 and 2001. During 1998, our primary emphasis was implementation of the field's largest waterflood unit, the East Heidelberg Waterflood Unit, plus other developmental drilling. During 1999, we began to see response from our waterflood efforts. We added other waterflood units during 1999 and 2000 and also expanded our drilling for natural gas at Heidelberg in the Selma Chalk formation during the second half of 1999. As a result, the natural gas production at Heidelberg has increased from 0.5 MMcf/d in 1998 to 1.0 MMcf/d in 1999, 3.8 MMcf/d in 2000 and 7.4 MMcf/d in 2001. We believe that our production at Heidelberg has peaked, but it should remain relatively stable for another year or two before there are any significant declines.

Production at King Bee Field averaged 415 BOE/d for 1999 (as we owned the field for only seven months of the year), 738 BOE/d in 2000 and 813 BOE/d in 2001. Production at Little Creek Field has also increased since we acquired it in August 1999. At the time of acquisition, Little Creek was producing approximately 1,350 BOE/d, with a 1999 annual average production rate of 587 BOE/d, due to the partial year ownership. Since acquiring the field, we have completed Phase III of the CO_2 flood and implemented Phases IV and V, resulting in gradual production increases. Production from Little Creek Field averaged 2,018 BOE/d for 2000 and 2,441 BOE/d for 2001, averaging 3,052 BOE/d during the fourth quarter of 2001. We are continuing to expand our tertiary recovery operations at Little Creek and anticipate that production will continue to increase at this field throughout 2002 and perhaps into 2003.

During the fourth quarter of 2000, we completed the $56.5 million acquisition of the Thornwell, Porte Barre and Iberia Fields located in Southwestern Louisiana, where the wells principally produce natural gas. The largest of these fields, Thornwell Field, contributed 1,053 BOE/d to our average production rate for 2000 and approximately 4,190 BOE/d to our 2000 fourth quarter average production volumes. Even though Thornwell Field had a relatively short expected life of approximately three years, based on initial estimates of its proven reserves, and thus was expected to rapidly decline, through our development and exploratory drilling program, the field's production increased in 2001, with an average rate of 4,275 BOE/d and an exit rate in the fourth quarter of 2001 of 4,902 BOE/d.

In total, our production increased 9,786 BOE/d, or 46%, between 2000 and 2001. The most significant factor in this increase was the purchase of Matrix in early July 2001. Production from the Matrix properties averaged approximately 7,000 BOE/d during the six months that we owned Matrix, contributing 3,524 BOE/d to our annual average, or approximately 36% of the increase year-over-year. The Matrix properties were producing approximately 6,667 BOE/d at the time of acquisition. Other significant increases are the changes outlined above at Heidelberg (598 BOE/d), King Bee (75 BOE/d), Little Creek (423 BOE/d) and Thornwell Fields (3,222 BOE/d). Another significant increase in production came from development and exploration drilling at Lirette Field, which increased 809 BOE/d in 2001.

REVENUE. Our oil and natural gas revenues more than doubled between 1999 and 2000, and further increased an additional 56% in 2001. Between 1999 and 2000, revenues increased 120% as both commodity prices and production increased substantially, partially offset by cash payments on our hedges. The overall increase in production volumes contributed $25.5 million or 26% of the increase, and the increase in commodity prices contributed $88.1 million or 90% of the increase, partially offset by $15.8 million in incremental cash payments we made on hedges (or a negative 16%). Between 2000 and 2001, revenues increased 56%, primarily from higher production levels. The overall increase in production volumes contributed $92.8 million or 93% of the increase, and the incremental cash receipts from hedges contributed $43.9 million or 44% of the increase, partially offset by an overall decrease of $37.0 million in commodity prices (or a negative 37%).

During 1999, we paid out $8.6 million for losses on our oil hedges ($1.95 per Bbl) and $126,000 for losses on our natural gas hedges, and we expensed $672,000 in 1999 that we paid to buy out a portion of our natural gas hedges for the next year. During 2000, we paid out $13.3 million ($2.39 per Bbl) on our oil hedges and $11.9 million ($0.88 per Mcf) on our natural gas hedges. In contrast, during 2001, we collected $1.9 million ($0.31 per Bbl) on our oil hedges and $16.7 million ($0.54 per Mcf) on our natural gas hedges. See "Market Risk Management" for a further discussion of our hedging activities.

OPERATING EXPENSES. Between 1999 and 2000, our oil and natural gas lease operating expenses, including production taxes and marketing expenses, increased 23% on a per BOE basis, primarily due to an increase in production taxes related to higher product prices, the addition of Little Creek Field during the third quarter of 1999 (which has higher operating costs per barrel due to tertiary recovery operations), and overall increases in the number of wells and in the cost of equipment and services.

Oil and natural gas lease operating expenses decreased 2% on a per BOE basis between 2000 and 2001, as a result of the addition of the Matrix natural gas properties in July 2001 and savings resulting from our ownership of CO_2 purchased in February 2001. These savings were partially offset by overall higher service and equipment costs in the industry during the year. The Matrix acquisition added predominately natural gas, which typically has a lower per unit operating cost than oil properties. Operating expenses per BOE averaged $4.06 for the Matrix properties during the six months of ownership, which was less than our overall average of $4.84 for 2001.

We reduced operating expenses by approximately $2.6 million during 2001 because of our CO2 acquisition in February 2001. Prior to the acquisition, we were paying approximately $0.25 per thousand cubic feet for CO2 that we used in our tertiary recovery operations at Little Creek Field. Now that we own the CO2, our cost is now our proportional share of the operating expenses of the CO2 field and pipeline, allocated based on the volumes of CO2 sold to commercial users and used for our own account. During 2001, this translated into an average operating cost of approximately $0.07 for each thousand cubic feet of CO2 produced, a savings of approximately $0.18 per thousand cubic feet of CO2. Our estimated total "all-in" cost per thousand cubic feet of CO2 is approximately $0.15 per thousand cubic feet after inclusion of the non-cash depreciation and amortization expense.

Operating costs at Little Creek Field averaged $12.45, $11.89 and $9.80 per BOE for 1999, 2000 and 2001 respectively. These costs per barrel are almost double the average for our operating costs on our other properties. While we were able to lower costs in 2001 because of our CO2 acquisition in February, we expect operating expenses to remain relatively high on this field, particularly in the near future, as we are initiating additional phases of tertiary recovery. Over the life of the property, we anticipate that operating expenses will average a bit less than the current levels, as we expect production to increase and we will ultimately reduce the amount of CO2 that we inject. Our other tertiary recovery operations are also expected to have a higher than average operating cost. However, even though operating expenses for these floods are higher than average, since the oil production from these fields is light, sweet oil that commands a premium price, the net operating income from these tertiary recovery operations is almost the same as our net operating income from our biggest field, Heidelberg Field.

Production taxes and marketing expenses decreased $0.06 per BOE (6%) in 2001 due to slightly lower commodity prices and the addition of the Matrix properties, a portion of which are tax exempt due to their offshore location, partially offset by higher marketing expenses on the offshore properties primarily relating to incremental processing and transportation costs.

CO2 OPERATIONS: In addition to using CO2 for our own account, we sell CO2 to third party industrial users under long-term contracts. Our net operating cash flow from these sales was $4.3 million during 2001. Our average CO2 production during 2001 was approximately 84 million cubic feet per day, of which approximately 53% was used in our tertiary recovery operations and the balance sold to other third parties for industrial use.

General and Administrative Expenses

We lowered our general and administrative ("G&A") expenses on a per BOE basis in both 2000 and 2001. Our gross G&A expense increased each year, but with the significant production increases, G&A expense on a per BOE basis declined.

Amounts in Thousands Except Per BOE and Employee Data	Year Ended December 31, 2001	2000	1999
Gross G&A expense	$ 33,727	$ 24,941	$ 20,119
State franchise taxes	877	467	346
Operator overhead charges	(20,328)	(13,684)	(10,278)
Capitalized exploration expense	(4,102)	(3,202)	(2,812)
Net G&A expense	$ 10,174	$ 8,522	$ 7,375
Average G&A expense per BOE	$ 0.89	$ 1.09	$ 1.21
Employees as of December 31	320	242	220

Our overall activity level has increased each year since 1998. As a result, we have had general increases in consultant fees, hired additional personnel, moved to a new office building in 1999, and have given salary increases and bonuses each year. The bonuses, as authorized by our board of directors, were at the midpoint of the bonus range in 1999, but were at the upper end of the range in 2000 and 2001, based primarily on our overall financial and operating results. Partially offsetting the overall increase in gross G&A costs are the increases in operator overhead charges and capitalized exploration expenses. The respective well operating agreements allow us, when we are the operator, to charge a specified overhead rate during the drilling phase and to charge a monthly fixed overhead rate for each producing well. As a result of the general escalation in activity each year and the addition of more operated wells from our recent acquisitions, this recovery of G&A increased from $10.3 million in 1999 to $13.7 million in 2000 and to $20.3 million in 2001. As a result, net G&A expense increased only 16% in 2000 and 19% in 2001, even though gross G&A expense increased 24% and 35% respectively.

On a per BOE basis, G&A costs decreased 10% in 2000 and an additional 18% in 2001 due to a higher percentage increase in production than in net G&A expense.

Interest and Financing Expenses

Amounts in Thousands Except Per BOE Data	Year Ended December 31, 2001	2000	1999
Interest expense	$ 22,335	$ 15,255	$ 15,795
Non-cash interest expense	(1,665)	(945)	(834)
Cash interest expense	20,670	14,310	14,961
Interest and other income	(849)	(2,279)	(1,415)
Net cash interest expense	$ 19,821	$ 12,031	$ 13,546
Average net cash interest expense per BOE	$ 1.74	$ 1.54	$ 2.22
Average debt outstanding	$ 264,792	$ 160,884	$ 172,010
Average interest rate (1)	7.8%	8.9%	8.7%

(1) Includes commitment fees but excludes amortization of debt issue costs.

We began 1999 with $225 million of total debt and further increased this to $234.6 million by the end of the first quarter. This debt was reduced by $100 million in April 1999 with the proceeds from the sale of common shares to affiliates of the Texas Pacific Group. We borrowed an additional $17.9 million during the second and third quarters to fund acquisitions, bringing total bank debt to $27.5 million and total outstanding debt to $152.5 million as of December 31, 1999.

During 2000, we made small reductions in our bank debt during the first three quarters, reducing total debt outstanding by $6.5 million during the first nine months. During the fourth quarter of 2000, we borrowed $61 million to fund property acquisitions and related hedges, but repaid $8.0 million from cash flow, ending the year with $199 million of long-term debt outstanding. The net effect was a 6% average lower level of debt in 2000 as compared to 1999, although the debt was at slightly higher average interest rates. During 2000 we generated $864,000 of other income, which also helped reduce our net cash interest expense. Overall, we had an 11% reduction in net cash interest expense between 1999 and 2000 with a 31% reduction on a BOE basis due to the increase in production levels during 2000.

During 2001, we had total bank borrowings of $146.0 million, primarily to fund our acquisition of Matrix ($100.0 million) and the CO_2 acquisition ($42.0 million). We repaid a total of $79.1 million during the year, of which (i) $13.0 million related to excess cash flow generated from operations early in the year given the unusually high natural gas prices and (ii) $65.9 million represented the net proceeds of our issuance of Series B 9% Senior Subordinated Notes due 2008 in August 2001. These notes were issued at a discount with an estimated yield to maturity of 10 7/8%. Our total outstanding debt increased from $199 million as of December 31, 2000, to $340.9 million as of December 31, 2001 (excluding the unamortized issue discount), a 71% increase. Our average interest rate decreased in 2001 due to an overall drop in interest rates, even though we issued an additional $75 million of subordinated debt in August at a relatively high interest rate. Overall, we had a 65% increase in net cash interest expense in 2001, but only a 13% increase on a BOE basis due to the overall production increases.

Depletion, Depreciation and Site Restoration

Depletion, depreciation and amortization ("DD&A") was at its lowest rate on a per BOE basis in our history in 1999 as a result of the full cost pool writedowns in 1998. Since that time, our DD&A rate has increased each year as our overall finding cost has been greater than the abnormally low rate in 1999, particularly the finding cost of our recent acquisitions.

	Year Ended December 31,		
Amounts in Thousands Except Per BOE Data	2001	2000	1999
Depletion and depreciation	$ 66,402	$ 34,530	$ 24,277
Depreciation of CO_2 assets	1,572	-	-
Site restoration provision	1,946	560	384
Depreciation of other fixed assets	1,425	1,124	854
Total DD&A	$ 71,345	$ 36,214	$ 25,515
Average DD&A cost per BOE	$ 6.27	$ 4.62	$ 4.17

The NYMEX oil price used for our reserve report increased slightly from $25.60 per Bbl as of December 31, 1999, to $26.80 per Bbl as of December 31, 2000, although natural gas prices increased almost fivefold, from $2.12 per Mcf in 1999 to $9.78 per Mcf in 2000. However, since the economic lives of most of our natural gas properties are generally not as sensitive to changes in commodity price, this change in price only increased our proved reserve quantities by 730,000 BOE between the two respective year-ends. During 2000, we also added 34.9 MMBOEs from acquisitions, other development work, and upward revisions. Consequently, our total proved reserve quantities increased 45% from 60.2 MMBOE as of December 31, 1999, to 87.4 MMBOE as of December 31, 2000.

Graph depicting our proved reserves (MMBOE):

	December 31,		
	1999	2000	2001
Oil	51.8	70.7	76.5
Natural Gas	8.4	16.7	33.0
Total MMBOE	60.2	87.4	109.5

Between 2000 and 2001, the NYMEX oil price used for our reserve report decreased from $26.80 per Bbl as of December 31, 2000, to $19.84 per Bbl as of December 31, 2001. Natural gas prices dropped almost fourfold, from $9.78 per Mcf in 2000 to $2.57 per Mcf in 2001. These declines in commodity prices, particularly oil, reduced the economic lives of our properties and reduced reserve quantities by 8.3 MMBOE. Overall, we showed a 25% increase in reserve quantities during 2001, as we added 41.8 MMBOEs from acquisitions, other development work, and upward revisions. Our total proved reserve quantities increased from 87.4 MMBOE as of December 31, 2000, to 109.5 MMBOE as of December 31, 2001.

Our DD&A rate increase from $4.17 per BOE in 1999 to $4.62 per BOE in 2000 was primarily a result of our property acquisition in the fourth quarter of 2000 at a higher than average cost per BOE. Because of the high commodity price environment, our average acquisition cost in 2000 was $11.94 per BOE, significantly higher than our average historical acquisition or finding cost per BOE and higher than the prior year's DD&A rate per BOE. Even though the high cost per BOE of these acquisitions increased our DD&A rate, thus far we have made a good rate of return on these properties. As of December 31, 2001, all but $5.1 million of the acquisition cost had been recovered (excluding the income from related natural gas hedges during the year), and these properties have a PV10 value as of December 31, 2001 of $30.3 million.

Similar to 2000, in 2001 our DD&A rate increased from $4.62 per BOE in 2000 to an average rate of $6.27 per BOE ($7.19 per BOE during the second half of the year after the Matrix acquisition), primarily as result of our acquisition of Matrix in July 2001. This acquisition also had a higher than average cost per BOE ($13.28 per BOE including unevaluated property costs) because of the high commodity price environment. We attempted to protect this acquisition with the purchase of natural gas price floors through 2003; however, the hedges for 2002 and 2003 were purchased from Enron, which declared bankruptcy in December 2001 (see "Market Risk Management" below for a discussion about these floors). Even so, we have increased our reserve quantities from this acquisition since July 2001 by 35% (or 46% by adding back production) and we still have most of the probable and possible reserves to exploit. Although our PV10 value at December 31, 2001 is approximately $31.9 million less than our net unrecovered cost, we believe that this acquisition will provide us a reasonable rate of return if natural gas prices recover somewhat and we are able to further exploit these properties.

We provide for the estimated future costs of well abandonment and site reclamation, net of any anticipated salvage, on a unit-of-production basis. This provision is included in DD&A expense and has increased each year along with the general increase in the number of our properties, especially the acquisition of our offshore properties.

Under full cost accounting rules, we are required each quarter to perform a ceiling test calculation. We did not have any full cost pool ceiling test writedowns in 1999, 2000 or 2001. However, as of December 31, 2001 the excess value under our ceiling test was quite small, and thus it is possible that we could be required to writedown our full cost pool in forthcoming periods if commodity prices do not recover or if they deteriorate.

Income Taxes

For the year ended December 31, 1999, a normal deferred tax provision would have resulted in a deferred income tax provision of $1.7 million. However, we utilized a portion of our deferred tax asset and its corresponding valuation allowance to offset this provision, leaving a net deferred tax asset as of December 31, 1999 of $95.1 million. At that time we believed that it was more likely than not that future taxable income would not be sufficient to realize the benefit from our deferred tax assets, so the deferred tax asset was left fully impaired, as it was at the prior year-end.

For the year ended December 31, 2000, we had taxable income of $27.6 million, but were able to offset this income with our tax net operating loss carryforwards ("NOLs"). We did incur $558,000 of current income tax expense during 2000 which related to alternative minimum taxes that could not be offset by NOLs. For the year ended December 31, 2000, a normal tax provision would have resulted in income tax expense of $27.7 million. However, we utilized a portion of our deferred tax assets and its corresponding valuation allowance to offset this provision. We also reevaluated the remaining balance of $67.9 million relating to our net deferred tax asset as of December 31, 2000. We concluded that it is more likely than not that there will be sufficient future taxable income to be able to realize the tax benefits of our deferred tax asset, resulting in a deferred tax benefit of $67.9 million and a net deferred tax asset balance as of December 31, 2001 of $67.9 million, none of which was impaired.

With the adjustment to deferred taxes in 2000, we began booking a normal tax provision in 2001. In 2001, we began to recognize the amount of enhanced oil recovery credits that we had earned to date from our tertiary projects which totaled $5.3 million at year-end 2001. As a result of these credits, our effective tax provision for 2001 was lowered from 37% to 30.5%. Most of this provision was deferred as we were able to offset our taxable income with our NOLs. The current portion of the tax provision relates to alternative minimum taxes that cannot be offset by NOLs.

	Year Ended December 31,		
Amounts in Thousands Except Per Unit Amounts	2001	2000	1999
Current income tax expense	$ 640	$ 558	$ -
Deferred income tax provision (benefit)	24,184	(67,852)	-
Total income tax provision (benefit)	$ 24,824	$ (67,294)	$ -
Average income tax provision (benefit) per BOE	$ 2.18	$ (8.59)	$ -
Net operating loss carryforwards	91,220	112,690	139,859
Net deferred tax asset (liability)	$ (17,433)	$ 67,852	$ 95,137
Valuation allowance	-	-	(95,137)
Total net deferred tax asset (liability)	$ (17,433)	$ 67,852	$ -

Results of Operations on a BOE Basis

The following table summarizes the cash flow, DD&A and results of operations on a BOE basis for the comparative periods. Each of the individual components is discussed above.

	Year Ended December 31,		
Per BOE Data	2001	2000	1999
Oil and natural gas revenues	$22.88	$26.13	$14.88
Gain (loss) on settlements of derivative contracts	1.64	(3.23)	(1.54)
Lease operating costs	(4.84)	(4.94)	(4.25)
Production taxes and marketing expense	(0.96)	(1.02)	(0.60)
Production netback	18.72	16.94	8.49
Operating cash flow from CO2 operations	0.38	-	-
General and administrative expense	(0.89)	(1.09)	(1.21)
Net cash interest expense	(1.74)	(1.54)	(2.22)
Current income taxes and other	(0.06)	(0.07)	0.11
Cash flow from operations (1)	16.41	14.24	5.17
DD&A	(6.27)	(4.62)	(4.17)
Deferred income taxes	(2.12)	8.66	-
Amortization of derivative contracts and other non-cash hedging adjustments	(2.90)	-	-
Other non-cash items	(0.15)	(0.12)	(0.25)
Net income	$ 4.97	$18.16	$ 0.75

(1) Represents cash flow provided by operations, exclusive of the net change in non-cash working capital balances.

MARKET RISK MANAGEMENT

We finance some of our acquisitions and other expenditures with fixed and variable rate debt. These debt agreements expose us to market risk related to changes in interest rates. We do not hold or issue derivative financial instruments for trading purposes.

The following table presents the carrying and fair values of our debt, along with average interest rates. The fair value of our bank debt is considered to be the same as the carrying value because the interest rate is based on floating short-term interest rates. The fair value of the subordinated debt is based on quoted market prices. None of our debt has any triggers or covenants regarding our debt ratings with rating agencies.

	Expected Maturity Dates				Total	Fair
Amounts in Thousands	2002	2003	2004-2007	2008	Value	Value
Variable rate debt:						
Bank debt	$ -	$ 140,870	$ -	$ -	$ 140,870	$ 140,870
The average interest rate on the bank debt at December 31, 2001 is 4.2%.						
Fixed rate debt:						
Subordinated debt	$ -	$ -	$ -	$ 200,000	$ 200,000	$ 188,000
The interest rate on the subordinated debt is a fixed rate of 9%.						

We enter into various financial contracts to hedge our exposure to commodity price risk associated with anticipated future oil and natural gas production. These contracts have historically consisted of price floors, collars and fixed price swaps. We generally attempt to hedge between 50% and 75% of our anticipated production each year to provide us with a reasonably certain amount of cash flow to cover most of our budget without incurring significant debt. When we make an acquisition, we attempt to hedge 75% to 100% of the forecasted production for the next year or two following the acquisition in order to help provide us with a minimum return on our investment. Most of our recent hedging activity has been the purchase of puts or price floors; however, we will also use instruments like collars if we think that the ceiling prices are high enough that we are not giving up a significant portion of the potential upside. All of the mark-to-market valuations used for our financial derivatives are provided by external sources and are based on prices that are actively quoted. We manage and control market and counterparty credit risk through established internal control procedures which are reviewed on an ongoing basis. We attempt to minimize credit risk exposure to counterparties through formal credit policies, monitoring procedures, and diversification.

Oil Hedges Historical Data

During March and April 1999, we entered into two no-cost contracts to hedge a portion of our oil production. The first contract was a fixed price swap for 3,000 Bbls/d from April through December 1999 at a price of $14.24 per Bbl. The second contract was a collar to hedge 3,000 Bbls/d from May 1999 through December 2000 with a floor price of $14.00 per Bbl and a ceiling price of $18.05 per Bbl. During 1999, we paid out approximately $8.6 million on these contracts and during 2000, we paid out $13.3 million relating to these oil collars.

During 2000, we purchased a $22.00 price floor on our 2001 production covering 12,800 Bbls/d at an aggregate cost of $1.8 million. This contract covered approximately 75% of our anticipated 2001 oil production, excluding any anticipated production from acquisitions. During 2001, we collected $1.9 million on this price floor.

During July 2001, we acquired a $21.00 price floor on 10,000 Bbls/d for 2002 production at an aggregate cost of approximately $4.7 million. This price floor covers approximately 60% of our anticipated oil production for 2002.

Natural Gas Hedges Historical Data

As of January 1, 1999, we had no-cost financial contracts ("collars") in place that hedged a total of 40 MMcf/d through August 1999 and 30 MMcf/d thereafter through December 2000. The first set of contracts had a weighted average ceiling price of approximately $2.95 per MMBtu and the second set of contracts had a ceiling price of $2.58 per MMBtu. Both contracts had a price floor of $1.90 per MMBtu. During 1999, we paid out a net of $0.8 million on these contracts, including $0.7 million paid to retire a portion of the hedge. During 2000, we paid out $11.9 million relating to these same natural gas collars.

During 2000, we purchased a $2.80 price floor on our 2001 production covering 37,500 MMBtu/d at an aggregate cost of $0.8 million. This contract covered approximately 75% of our anticipated 2001 natural gas production, excluding any anticipated production from acquisitions. During 2001, we collected $1.8 million on this price floor.

At the same time that we acquired Thornwell Field, we purchased price floors for these predominately natural gas properties that we acquired in the fourth quarter of 2000. The price floors covered nearly all of the anticipated proven natural gas production from these properties for 2001 and 2002. These floors cost $2.5 million with varying volumes and price floors each quarter for 2001 and 2002. During 2001, we collected $2.2 million from these price floors.

For the Matrix properties we acquired in July 2001 (see also "Matrix Acquisition" above), we attempted to protect our investment with the purchase of price floors covering nearly all of the forecasted proven natural gas production through December 2003, with a minimum price of $4.25 per MMBtu for July 2001 through December 2002 and $3.75 per MMBtu for all of 2003, at a total cost of $18.0 million. Subsequent to the acquisition, natural gas prices began to decline and we were paid approximately $12.7 million on these price floors during 2001. Unfortunately, the price floors relating to 2002 and 2003 were purchased from Enron, which filed bankruptcy in December 2001. We sold our bankruptcy claim against Enron in February 2002 for approximately $9.2 million. In total, we collected approximately $21.9 million from our price floors relating to the Matrix acquisition, a net cash gain of approximately $3.9 million, although we have suffered an opportunity loss in light of the drop in natural gas prices since the date of acquisition and the loss of our 2002 and 2003 hedges.

When Enron filed for bankruptcy during the fourth quarter of 2001 these Enron hedges ceased to qualify for hedge accounting treatment. Therefore, as required by Financial Accounting Standards No. 133, the accounting treatment changed at that point in time. The result is that any future changes in the current market value of these assets must be reflected in our income statement and any remaining other comprehensive income (part of equity) left at the time of the accounting change must be amortized over the original expected life of the hedges. To adjust the Enron hedges down to the current market value, which we determined to be the amount that we sold the claims for in February 2002, we took a pre-tax write down of $24.4 million in the fourth quarter of 2001. The other comprehensive income previously recorded as part of the mark-to-market value adjustment each quarter remained to be amortized over 2002 and 2003, the periods during which these hedges would have expired. The result is that we will have pre-tax income attributable to these Enron hedges during 2002 of approximately $13.4 million and pre-tax income during 2003 of approximately $5.1 million as we reverse the September 30, 2001 balance of other comprehensive income relating to these hedges. The three year total pre-tax net loss will be approximately $5.9 million, which approximates the difference between the amount collected and paid for the Enron portion of the Matrix price floors.

Subsequent to the Enron bankruptcy, we purchased additional hedges to protect against any further deterioration in natural gas prices. These have a floor price of $2.50 per MMBtu and an average ceiling price of around $4.15 per MMBtu and cover not only the anticipated gas production from the Matrix properties, but a substantial portion of our other natural gas production as well. Overall, these hedges, which were purchased from four different financial institutions, cover approximately 75% of our forecasted total 2002 natural gas production.

Summary

During 1999, we paid out $8.6 million for losses on our oil hedges ($1.95 per Bbl) and $126,000 for losses on our natural gas hedges, plus we expensed $672,000 in 1999 that we paid to buy out a portion of our natural gas hedges for the next year. During 2000, we paid out $13.3 million ($2.39

per Bbl) on our oil hedges and $11.9 million ($0.88 per Mcf) on our natural gas hedges. In contrast, during 2001, we collected $1.9 million ($0.31 per Bbl) on our oil hedges and $16.7 million ($0.54 per Mcf) on our natural gas hedges.

Hedges as of December 31, 2001

The following table lists all of our individual hedges in place as of December 31, 2001.

Period	Volume Per Day	Floor Price
Oil Price Floors (Bbls/d):		
2002	10,000	$21.00
Gas Price Floors (MMBtu/d):		
Q1 -2002	5,269	$3.65
Q2 -2002	3,775	$3.40
Q3 -2002	2,873	$3.38
Q4 -2002	2,135	$3.38

Period	Volume Per Day	Floor Price	Ceiling Price
Gas Price Collars (MMBtu/d):			
2002	20,000	$2.50	$4.10
2002	20,000	$2.50	$4.10
2002	25,000	$2.50	$4.20
2002	25,000	$2.50	$4.17

In February 2002 we acquired no-cost collars covering 70 MMcf/d during calendar 2003 with a floor price of $2.75 per MMBtu and a weighted average ceiling price of $4.025 per MMBtu. Although we have not completed our forecast for 2003, we expect that these hedges will cover between 50% and 75% of our anticipated 2003 natural gas production.

Including the Enron hedges discussed above, at December 31, 2001, the fair value of our derivative contracts was approximately $23.5 million, an increase of approximately $18.4 million over the $5.1 million recorded as of December 31, 2000, which represented the cost of hedges in existence at that time before the adoption of SFAS No. 133. The increase is due to both additional funds spent in 2001 to purchase hedges and to an increase in the fair market value of these hedges due to a decline in commodity prices between the time of the purchase and year-end 2001. The balance in other comprehensive income represents the excess of fair market value over cost related to our hedges, net of related income taxes, and also includes the remaining other comprehensive income booked as of September 30, 2001 relating to the Enron hedges, as these assets are no longer accounted for with hedge accounting treatment due to the Enron bankruptcy. The other comprehensive income relating to these Enron hedges will be reversed in 2002 and 2003, during the periods that the hedges would have otherwise expired. The adjustment to their current market value was a $24.4 million expense in the fourth quarter of 2001. All but $3.2 million of the $14.2 million in accumulated other comprehensive income as of December 31, 2001 relates to contracts that will expire within the next 12 months, including $8.4 million related to the Enron hedges, and will be reclassified out of other comprehensive income during 2002. During 2001 we reclassified approximately $1.0 million out of other comprehensive income and into derivative contracts fair value loss in the consolidated statements of operations, relating to the adjustment made at January 1, 2001 as part of the adoption of SFAS No. 133. In addition, we expensed approximately $5.3 million during the year relating to the amortization of the cost of the price floors.

Based on futures market prices at December 31, 2001, we would expect to receive approximately $0.9 million on our natural gas floor contracts and $2.2 million on our oil floor contracts, all of which expire as of the end of 2002. If the natural gas futures market prices were to decline by 10%, the amount expected to be received under our natural gas floor contracts during 2002 would increase to approximately $3.5 million, and if natural gas futures market prices were to increase by 10%, the amount expected to be received under our natural gas floor contracts would decrease to approximately $0.6 million. If crude oil prices were to decrease by 10%, we would expect to receive approximately $9.7 million on our oil floor contracts, and if crude oil prices were to increase by 10%, we would not expect to receive any payment on our oil floor contracts.

CRITICAL ACCOUNTING POLICIES

Our significant accounting policies are included in Note 1 to the Consolidated Financial Statements. These policies, along with the underlying assumptions and judgments by our management in their application, have a significant impact on our consolidated financial statements. We consider our most critical accounting policies are those related to property and equipment and hedging activities.

Property, Plant and Equipment

We follow the full-cost method of accounting for oil and natural gas properties. Under this method of accounting, the estimated quantities of proved oil and natural gas reserves used to compute depletion and the related present value of estimated future net cash flows therefrom used to perform the full-cost ceiling test have a significant impact on the underlying financial statements. The process of estimating oil and natural gas reserves is very complex, requiring significant decisions in the evaluation of all available geological, geophysical, engineering and economic data. The data for a given field may also change substantially over time as a result of numerous factors, including additional development activity, evolving production history and continued reassessment of the viability of production under varying economic conditions. As a result, material revisions to existing reserve estimates may occur from time to time. Although every reasonable effort is made to ensure that the reported reserve estimates represent the most accurate assessments possible, including the hiring of independent engineers to prepare the report, the subjective decisions and variances in available data for various fields make these estimates generally less precise than other estimates included in the financial statement disclosures. Changes in the reserve data could have a significant impact on our financial statements.

Hedging Activities

We enter into derivative contracts (i.e. hedges) to mitigate our exposure to commodity price risk associated with future oil and natural gas production. These contracts have historically consisted of options, in the form of price floors or collars, and fixed price swaps. With the adoption of SFAS No. 133 in 2001, every derivative instrument must be recorded on the balance sheet as either an asset or a liability measured at its fair value. If the derivative does not qualify as a hedge or is not designated as a hedge, the change in fair value of the derivative is recognized currently in earnings. If the derivative qualifies for hedge accounting, the change in fair value of the derivative is recognized in other comprehensive income (equity), assuming that the hedge is effective.

In order to qualify for hedge accounting, the changes in fair value or cash flows of the hedging instruments and the hedged items must have a high degree of correlation (i.e. be effective). We measure and compute the hedge effectiveness on a quarterly basis. If a hedging instrument becomes ineffective, the hedge accounting is discontinued and any deferred gains or losses on the cash flow hedge remain in accumulated other comprehensive income until the periods during which the hedges would have otherwise expired. If we determine that it is probable that a hedged forecasted transaction will not occur, deferred gains or losses on the hedging instrument are recognized in earnings immediately.

All of our current derivative hedging instruments qualify for hedge accounting. However, during 2001 we had one hedge with Enron that initially qualified for hedge accounting, but its status changed when Enron filed bankruptcy, causing us to change our accounting treatment of this asset before the hedge would have expired. Due to the volatility during the year in the market value of our hedges caused primarily by changing commodity prices, the related asset values on our balance sheet can change dramatically. If a hedge ceases to qualify for hedge accounting as did the hedges purchased from Enron, the adjustments in market value are recorded in the income statement rather than as part of equity. These adjustments can be material to our financial statements.

The preparation of financial statements requires us to make other estimates and assumptions that affect the reported amounts of certain assets, liabilities, revenues and expenses during each reporting period. We believe that our estimates and assumptions are reasonable and reliable and believe that the ultimate actual results will not differ significantly from those reported; however, such estimates and assumptions are subject to a number of risks and uncertainties and such risks and uncertainties could cause the actual results to differ materially from our estimates.

RECENTLY ISSUED ACCOUNTING PRONOUNCEMENTS

In July 2001, the Financial Accounting Standards Board ("FASB") issued Statement of Financial Accounting Standards No. 141 ("SFAS No. 141"), "Business Combinations," Statement of Financial Accounting Standards No. 142 ("SFAS No. 142"), "Goodwill and Other Intangible Assets," and Statement of Financial Accounting Standards No. 143 ("SFAS No. 143"), "Accounting for Asset Retirement Obligations."

SFAS No. 141 requires that the purchase method of accounting be used for all business combinations initiated or completed after June 30, 2001. SFAS No. 141 also specified criteria that intangible assets acquired in a purchase method business combination must be recognized and reported apart from goodwill. The adoption of SFAS No. 141 as of July 1, 2001 did not have an impact on our consolidated financial statements.

SFAS No. 142 requires that goodwill as well as other intangible assets with indefinite lives not be amortized but tested annually for impairment. The adoption of SFAS No. 142 will not have an impact on our consolidated financial statements.

SFAS No. 143 requires that the fair value of a liability for an asset retirement obligation be recorded in the period in which it is incurred and the corresponding cost capitalized by increasing the carrying amount of the related long-lived asset. The liability is accreted to its present value each period, and the capitalized cost is depreciated over the useful life of the related asset. If the liability is settled for an amount other than the recorded amount, a gain or loss is recognized. The standard is effective for us beginning in 2003, but earlier adoption is encouraged. Adoption of the standard will result in recording a cumulative effect of a change in accounting principle in the period of adoption. We have not yet determined the impact of this new standard or when we will adopt this new standard.

In August 2001, the FASB issued Statement of Financial Accounting Standards No. 144 ("SFAS No. 144"), "Accounting for the Impairment or Disposal of Long-Lived Assets." SFAS No. 144 addresses the financial accounting and reporting for the impairment or disposal of long-lived assets. SFAS No. 144 supersedes SFAS No. 121 but retains its fundamental provisions for the (a) recognition/measurement of impairment of long-lived assets to be held and used and (b) measurement of long-lived assets to be disposed of by sale. SFAS No. 144 also supersedes other pronouncements which currently do not affect our financial statements. SFAS No. 144 became effective for us beginning in 2002 and we do not expect this statement to have an impact on our consolidated financial statements.

FORWARD-LOOKING INFORMATION

The statements contained in this Annual Report on Form 10-K that are not historical facts, including, but not limited to, statements found in this Management's Discussion and Analysis of Financial Condition and Results of Operations, are forward-looking statements, as that term is defined in Section 21E of the Securities and Exchange Act of 1934, as amended, that involve a number of risks and uncertainties. Such forward- looking statements may be or may concern, among other things, capital expenditures, drilling activity, acquisition plans and proposals and dispositions, development activities, cost savings, production efforts and volumes, hydrocarbon reserves, hydrocarbon prices, liquidity, regulatory matters, mark-to-market values, and competition. Such forward-looking statements generally are accompanied by words such as "plan," "estimate," "expect," "predict," "anticipate," "projected," "should," "assume," "believe" or other words that convey the uncertainty of future events or outcomes. Such forward-looking information is based upon management's current plans, expectations, estimates and assumptions and is subject to a number of risks and uncertainties that could significantly affect current plans, anticipated actions, the timing of such actions and the Company's financial condition and results of operations. As a consequence, actual results may differ materially from expectations, estimates or assumptions expressed in or implied by any forward-looking statements made by or on behalf of the Company. Among the factors that could cause actual results to differ materially are: fluctuations of the prices received or demand for the Company's oil and natural gas, the uncertainty of drilling results and reserve estimates, operating hazards, acquisition risks, requirements for capital, general economic conditions, competition and government regulations, as well as the risks and uncertainties discussed in this annual report, including, without limitation, the portions referenced above, and the uncertainties set forth from time to time in the Company's other public reports, filings and public statements.

Independent Auditors' Report

To the Stockholders of Denbury Resources Inc.

We have audited the consolidated balance sheets of Denbury Resources Inc. as of December 31, 2001 and 2000 and the related consolidated statements of operations, stockholders' equity (deficit) and cash flows for each of the three years in the period ended December 31, 2001. These consolidated financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these consolidated financial statements based on our audits.

We conducted our audits in accordance with auditing standards generally accepted in the United States of America. 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, such consolidated financial statements present fairly in all material respects, the financial position of the Company as of December 31, 2001 and 2000 and the results of its operations and its 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 of America.

/s/ Deloitte & Touche LLP

Dallas, Texas
February 25, 2002

Consolidated Balance Sheets

AMOUNTS IN THOUSANDS	DECEMBER 31, 2001	DECEMBER 31, 2000
ASSETS		
CURRENT ASSETS		
Cash and cash equivalents	$ 23,496	$ 22,293
Accrued production receivables	22,823	37,527
Trade and other receivables, net of allowance of $233 and $227	32,512	5,739
Derivative assets	23,458	4,305
Deferred tax asset	989	28,126
Total current assets	103,278	97,990
PROPERTY AND EQUIPMENT		
Oil and natural gas properties (using full cost accounting)		
Proved	1,098,263	746,062
Unevaluated	44,521	13,810
CO2 properties and equipment	45,555	--
Less accumulated depletion and depreciation	(520,332)	(452,358)
Net property and equipment	668,007	307,514
OTHER ASSETS	18,703	12,149
NONCURRENT DEFERRED TAX ASSET	--	39,726
TOTAL ASSETS	$ 789,988	$ 457,379
LIABILITIES AND STOCKHOLDERS' EQUITY		
CURRENT LIABILITIES		
Accounts payable and accrued liabilities	$ 66,491	$ 26,628
Oil and gas production payable	13,447	12,158
Total current liabilities	79,938	38,786
LONG-TERM LIABILITIES		
Long-term debt	334,769	199,000
Provision for site reclamation costs	4,318	2,770
Deferred tax liability	18,422	--
Other	3,373	658
Total long-term liabilities	360,882	202,428
STOCKHOLDERS' EQUITY		
Preferred stock, $.001 par value, 25,000,000 shares authorized; none issued and outstanding	--	--
Common stock, $.001 par value, 100,000,000 shares authorized; 52,956,825 and 45,979,981 shares issued and outstanding at December 31, 2001 and December 31, 2000, respectively	53	46
Paid-in capital in excess of par	391,557	329,339
Accumulated deficit	(56,670)	(113,220)
Accumulated other comprehensive income	14,228	--
Total stockholders' equity	349,168	216,165
TOTAL LIABILITIES AND STOCKHOLDERS' EQUITY	$ 789,988	$ 457,379

See Notes to Consolidated Financial Statements.

Consolidated Statements of Operations

AMOUNTS IN THOUSANDS EXCEPT PER SHARE AMOUNTS	YEAR ENDED DECEMBER 31, 2001	2000	1999
REVENUES			
Oil, natural gas and related product sales	$ 260,398	$ 204,636	$ 90,991
CO2 sales	5,210	--	--
Gain (loss) on settlements of derivative contracts	18,654	(25,264)	(9,416)
Interest income and other	849	2,279	1,415
Total revenues	285,111	181,651	82,990
EXPENSES			
Lease operating costs	55,049	38,676	26,029
Production taxes and marketing expenses	10,963	8,051	3,662
CO2 operating costs	891	--	--
General and administrative	9,297	8,055	7,029
Interest	22,335	15,255	15,795
Depletion and depreciation	71,345	36,214	25,515
Franchise taxes	877	467	346
Loss on Enron related assets	25,164	--	--
Amortization of derivative contracts and other non-cash heding adjustments	7,816	--	--
Total expenses	203,737	106,718	78,376
Income before income taxes	81,374	74,933	4,614
Income tax provision (benefit)			
Current income taxes	640	558	--
Deferred income taxes	24,184	(67,852)	--
NET INCOME	$ 56,550	$ 142,227	$ 4,614
NET INCOME PER COMMON SHARE			
Basic	$ 1.15	$ 3.10	$ 0.12
Diluted	1.12	3.07	0.12
WEIGHTED AVERAGE COMMON SHARES OUTSTANDING			
Basic	49,325	45,823	39,928
Diluted	50,361	46,352	39,987

See Notes to Consolidated Financial Statements.

Consolidated Statements of Cash Flows

AMOUNTS IN THOUSANDS	2001	2000	1999
	YEAR ENDED DECEMBER 31,		
CASH FLOW FROM OPERATING ACTIVITIES:			
Net income	$ 56,550	$ 142,227	$ 4,614
Adjustments needed to reconcile to net cash flow provided by operations:			
Depletion and depreciation	71,345	36,214	25,515
Deferred income taxes	24,184	(67,852)	--
Non-cash loss on Enron related assets	25,164	--	--
Amortization of derivative contracts and other non-cash hedging adjustments	7,816	--	--
Other	1,742	966	1,490
	186,801	111,555	31,619
Changes in working capital items relating to operations:			
Accrued production receivables	19,987	(21,691)	(10,341)
Trade and other receivables	(16,371)	(2,797)	13,448
Derivative assets	(28,043)	--	--
Other assets	(976)	(5,109)	--
Accounts payable and accrued liabilities	23,560	8,586	4,472
Oil and gas production payable	(2,213)	5,038	2,002
Other liabilities	2,302	390	--
NET CASH PROVIDED BY OPERATING ACTIVITIES	185,047	95,972	41,200
CASH FLOW USED FOR INVESTING ACTIVITIES:			
Oil and natural gas expenditures	(170,109)	(73,736)	(34,479)
Acquisitions of oil and gas properties and Matrix, net of cash acquired	(97,871)	(60,285)	(20,488)
Acquisition of CO2 assets and capital expenditures	(45,555)	--	--
Net purchases of other assets	(1,799)	(1,629)	(1,381)
Increase in cash restricted for future site reclamation	(3,496)	(322)	(2,347)
Disposition of oil and gas properties	--	2,932	400
NET CASH USED FOR INVESTING ACTIVITIES	(318,830)	(133,040)	(58,295)
CASH FLOW FROM FINANCING ACTIVITIES:			
Bank repayments	(79,130)	(14,500)	(100,000)
Bank borrowings	146,000	61,000	27,500
Issuance of subordinated debt	68,528	--	--
Net proceeds from issuance of common stock	2,594	1,491	100,079
Costs of debt financing	(3,026)	(398)	(765)
Other	20	--	--
NET CASH PROVIDED BY FINANCING ACTIVITIES	134,986	47,593	26,814
NET INCREASE IN CASH AND CASH EQUIVALENTS	1,203	10,525	9,719
Cash and cash equivalents at beginning of year	22,293	11,768	2,049
CASH AND CASH EQUIVALENTS AT END OF YEAR	$ 23,496	$ 22,293	$ 11,768

See Notes to Consolidated Financial Statements.

Consolidated Statement of Changes in Stockholders' Equity (Deficit)

DOLLAR AMOUNTS IN THOUSANDS	Common Stock ($.001 Par Value) Shares	Amount	Paid-In Capital in Excess of Par	Retained Earnings (Accumulated Deficit)	Other Comprehensive Income	Total
BALANCE - JANUARY 1, 1999	26,801,680	$ 27	$ 227,769	$ (260,061)	$ --	$ (32,265)
Issued pursuant to employee stock purchase plan	363,930	--	1,544	--	--	1,544
Sale of common stock to TPG	18,552,876	19	98,516	--	--	98,535
Net income	--	--	--	4,614	--	4,614
BALANCE - DECEMBER 31, 1999	45,718,486	46	327,829	(255,447)	--	72,428
Issued pursuant to employee stock purchase plan	218,493	--	1,305	--	--	1,305
Issued pursuant to employee stock option plan	40,458	--	186	--	--	186
Issued pursuant to directors compensation plan	2,544	--	19	--	--	19
Net income	--	--	--	142,227	--	142,227
BALANCE - DECEMBER 31, 2000	45,979,981	46	329,339	(113,220)	--	216,165
Issued pursuant to employee stock purchase plan	189,485	--	1,546	--	--	1,546
Issued pursuant to employee stock option plan	209,600	--	1,048	--	--	1,048
Issued pursuant to directors compensation plan	7,829	--	63	--	--	63
Issued in Matrix acquisition	6,569,930	7	59,188	--	--	59,195
Tax benefit from stock options	--	--	373	--	--	373
Other comprehensive income	--	--	--	--	14,228	14,228
Net income	--	--	--	56,550	--	56,550
BALANCE - DECEMBER 31, 2001	52,956,825	$ 53	$ 391,557	$ (56,670)	$ 14,228	$ 349,168

See Notes to Consolidated Financial Statements.

Notes to Consolidated Financial Statements

NOTE 1. SIGNIFICANT ACCOUNTING POLICIES

Organization and Nature of Operations

Denbury Resources Inc. ("Denbury" or the "Company") is a Delaware corporation, organized under Delaware General Corporation Law, engaged in the acquisition, development, operation and exploration of oil and natural gas properties. The Company operates as one business segment, with its operating activities related to the exploration, development and production of oil and natural gas in the U.S. Gulf Coast region. In 2001 the Company acquired carbon dioxide ("CO2") reserves that are used in the Company's tertiary oil recovery operations. In addition, the Company sells some CO2 to third parties for industrial uses.

Principles of Reporting and Consolidation

The consolidated financial statements herein have been prepared in accordance with generally accepted accounting principles ("GAAP") in the United States and include the accounts of the Company and its subsidiaries, all of which are wholly owned. All material intercompany balances and transactions have been eliminated.

Oil and Natural Gas Operations

A) CAPITALIZED COSTS. The Company follows the full-cost method of accounting for oil and natural gas properties. Under this method, all costs related to acquisitions, exploration and development of oil and natural gas reserves are capitalized and accumulated in a single cost center representing the Company's activities undertaken exclusively in the United States. Such costs include lease acquisition costs, geological and geophysical expenditures, lease rentals on undeveloped properties, costs of drilling both productive and non-productive wells and general and administrative expenses directly related to exploration and development activities and do not include any costs related to production, general corporate overhead or similar activities. Proceeds received from disposals are credited against accumulated costs except when the sale represents a significant disposal of reserves, in which case a gain or loss is recognized.

B) DEPLETION AND DEPRECIATION. The costs capitalized, including production equipment, are depleted or depreciated on the unit-of-production method, based on proved oil and natural gas reserves as determined by independent petroleum engineers. Oil and natural gas reserves are converted to equivalent units based upon the relative energy content which is six thousand cubic feet of natural gas to one barrel of crude oil.

C) SITE RECLAMATION. Estimated future costs of well abandonment and site reclamation, including the removal of production facilities at the end of their useful life, are provided for on a unit-of-production basis. Costs are based on engineering estimates of the anticipated method and extent of site restoration, valued at year-end prices, net of estimated salvage value, and in accordance with the current legislation and industry practice. The annual provision for future site reclamation costs is included in depletion and depreciation expense and reported under long-term liabilities in the Consolidated Balance Sheets as "Provision for site reclamation costs."

D) CEILING TEST. The net capitalized costs of oil and natural gas properties are limited to the lower of unamortized cost or the cost center ceiling. The cost center ceiling is defined as the sum of (i) the present value of estimated future net revenues from proved reserves (discounted at 10%), based on unescalated period-end oil and natural gas prices; (ii) plus the cost of properties not being amortized; (iii) plus the lower of cost or estimated fair value of unproved properties included in the costs being amortized, if any; (iv) less related income tax effects. The cost center ceiling test is prepared quarterly.

E) JOINT INTEREST OPERATIONS. Substantially all of the Company's oil and natural gas exploration and production activities are conducted jointly with others. These financial statements reflect only the Company's proportionate interest in such activities and any amounts due from other partners are included in trade receivables.

Revenue Recognition

Revenue is recognized at the time oil and natural gas is produced and sold. Any amounts due from purchasers of oil and natural gas are included in accrued production receivables.

The Company follows the "sales method" of accounting for its oil and natural gas revenue, whereby the Company recognizes sales revenue on all oil or natural gas sold to its purchasers, regardless of whether the sales are proportionate to the Company's ownership in the property. A receivable or liability is recognized only to the extent that the Company has an imbalance on a specific property greater than the expected remaining proved reserves. As of December 31, 2001 and 2000, the Company's aggregate oil and natural gas imbalances were not material to its consolidated financial statements.

The Company recognizes revenue and expenses of purchased producing properties commencing from the closing or agreement date, at which time the Company also assumes control.

Derivative Instruments and Hedging Activities

The Company enters into derivative contracts to mitigate its exposure to commodity price risk associated with future oil and natural gas production. These contracts have historically consisted of options, in the form of price floors or collars, and fixed price swaps. On January 1, 2001, the Company adopted Statement of Financial Accounting Standards No. 133 ("SFAS No. 133"), "Accounting for Derivative Instruments and Hedging Activities," as amended. SFAS No. 133 requires that every derivative instrument be recorded on the balance sheet as either an asset or a liability measured at fair value. If the derivative does not qualify as a hedge or is not designated as a hedge, the change in fair value of the derivative is recognized currently in earnings. If the derivative qualifies for hedge accounting, the change in fair value of the derivative is recognized either currently in earnings or deferred in other comprehensive income (equity) depending on the type of hedge and to what extent the hedge is effective. All of the Company's current derivative hedging instruments are cash flow hedges.

As a result of the adoption of SFAS No. 133 on January 1, 2001, the Company recognized a $1.6 million increase in its derivative assets for the increase in fair value over the cost of hedging contracts in place at that time. The Company also recorded a corresponding increase to accumulated other comprehensive income of approximately $1.0 million, after tax, in the transition adjustment which was reclassified out of accumulated other comprehensive income to earnings over the remainder of 2001. A summary of the Company's comprehensive income for the year ended December 31, 2001 and balance in accumulated other comprehensive income at December 31, 2001 is included in Note 8 to the consolidated financial statements.

In order to qualify for hedge accounting the relationship between the hedging instruments and the hedged items must be highly effective in achieving the offset of changes in fair values or cash flows attributable to the hedged risk both at the inception of the hedge and on an ongoing basis. The Company measures hedge effectiveness on a quarterly basis. Hedge accounting is discontinued prospectively when a hedging instrument becomes ineffective. The Company assesses hedge effectiveness based on total changes in the fair value of options used in cash flow hedges rather than changes of intrinsic value only. As a result, changes in the entire fair value of option contracts are deferred in accumulated other comprehensive income, to the extent they are effective, until the hedged transaction is completed. If a hedge becomes ineffective, any deferred gains or losses on the cash flow hedge remain in accumulated other comprehensive income until the underlying production related to the derivative hedge has been delivered. If the Company determines that it is probable that a hedged forecasted transaction will not occur, deferred gains or losses on the hedging instrument are recognized in earnings immediately.

Gains or losses on settlements of the Company's derivative hedging instruments are recorded in "Gain (loss) on settlements of derivative contracts" included in revenues in the Company's Consolidated Statements of Operations. The Company applies Derivative Implementation Group Issue G20 in accounting for its net purchased and zero cost collars which allows the Company to amortize the cost of net purchased options over the period of the hedge. The Company records this amortization and other gains or losses resulting from hedge ineffectiveness in "Amortization of derivative contracts and other non-cash hedging adjustments" under expenses in the Consolidated Statements of Operations. The Company's hedging activities are further discussed in Note 7 to the consolidated financial statements.

Financial Instruments with Off-Balance-Sheet Risk and Concentrations of Credit Risk

The Company's financial instruments that are exposed to concentrations of credit risk consist primarily of cash equivalents and trade and accrued production receivables in addition to the derivative hedging instruments discussed above. The Company's cash equivalents represent high-quality securities placed with various investment grade institutions. This investment practice limits the Company's exposure to concentrations of credit risk. The Company's trade and accrued production receivables are dispersed among various customers and purchasers; therefore, concentrations of credit risk are limited. Also, the Company's more significant purchasers are large companies with excellent credit ratings. If customers are considered a credit risk, letters of credit are the primary security obtained to support lines of credit. The Company attempts to minimize its credit risk exposure to counterparties of its derivative hedging contracts through formal credit policies, monitoring procedures and diversification.

CO2 Operations

The Company owns CO2 reserves that it uses for its own tertiary oil recovery operations, and in addition sells a portion to third party industrial users. The Company records revenue from sales of CO2 to third parties when it is produced and sold. CO2 used for the Company's tertiary oil recovery operations is not recorded as revenue in the Company's Consolidated Statements of Operations. Expenses related to the production of CO2 are allocated between volumes sold to third parties and volumes used for the Company's own use. The expenses related to third party sales are recorded in "CO2 operating costs" and the expenses related to the Company's own uses are recorded in "Lease operating costs" in the Company's Consolidated Statements of Operations.

The Company capitalizes acquisitions and the costs of exploring and developing CO_2 reserves. The costs capitalized are depleted or depreciated on the unit-of-production method, based on proved CO_2 reserves as determined by independent engineers.

Cash Equivalents

The Company considers all highly liquid investments to be cash equivalents if they have maturities of three months or less at the date of purchase.

Restricted Cash

At December 31, 2001 and 2000, the Company had approximately $7.8 million and $2.7 million, respectively, of restricted cash held in escrow for future site reclamation costs. This restricted cash is included in "Other Assets" in the Consolidated Balance Sheets.

Net Income Per Common Share

Basic net income per common share is computed by dividing the net income attributable to common stockholders by the weighted average number of shares of common stock outstanding during the period. Diluted net income per common share is calculated in the same manner, but also considers the impact to net income and common shares for the potential dilution from stock options, stock warrants and any other outstanding convertible securities.

For each of the three years in the period ended December 31, 2001, there were no adjustments to net income for purposes of calculating basic and diluted net income per common share. The following is a reconciliation of the weighted average shares used in the basic and diluted income per common share computations:

	YEAR ENDED DECEMBER 31,		
AMOUNTS IN THOUSANDS	2001	2000	1999
Weighted average common shares - basic	49,325	45,823	39,928
Effect of diluted securities:			
Stock options .	1,036	529	59
Weighted average common shares - diluted	50,361	46,352	39,987

Options to purchase 1.8 million shares of common stock in 2001, 1.6 million shares of common stock in 2000 and 1.6 million shares of common stock in 1999 were excluded from the diluted net income per common share computation as the exercise prices of these options exceeded the average market price of the Company's common stock during the respective periods. Warrants representing 75,000 shares of common stock were also excluded from the 1999 diluted net income per share computation as the exercise price exceeded the average market price of the Company's common stock.

Income Taxes

Income taxes are accounted for using the liability method under which deferred income taxes are recognized for the future tax effects of temporary differences between the financial statement carrying amounts and the tax basis of existing assets and liabilities using the enacted statutory tax rates in effect at year end. The effect on deferred taxes for a change in tax rates is recognized in income in the period that includes the enactment date. A valuation allowance for deferred tax assets is recorded when it is more likely than not that the benefit from the deferred tax asset will not be realized.

Use of Estimates

The preparation of financial statements in conformity with GAAP requires management to make estimates and assumptions that affect the reported amount of certain 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 each reporting period. Management believes its estimates and assumptions are reasonable; however, such estimates and assumptions are subject to a number of risks and uncertainties that may cause actual results to differ materially from the Company's estimates. Significant estimates underlying these financial statements include the fair value of financial derivative instruments and the estimated quantities of proved oil and natural gas reserves used to compute depletion of oil and natural gas properties and the related present value of estimated future net cash flows therefrom.

Reclassifications

To conform to the current year presentation, the Company reclassified losses on settlements of derivative contracts of $25.3 million in 2000 and $9.4 million in 1999 which were previously reported in "Oil, natural gas and related product sales" to "Gain (loss) on settlements of derivative contracts" in the Consolidated Statements of Operations. These reclassifications had no impact on the total revenues reported by the Company.

Recently Issued Accounting Pronouncements

In July 2001, the Financial Accounting Standards Board ("FASB") issued Statement of Financial Accounting Standards No. 141 ("SFAS No. 141"), "Business Combinations," Statement of Financial Accounting Standards No. 142 ("SFAS No. 142"), "Goodwill and Other Intangible Assets," and Statement of Financial Accounting Standards No. 143 ("SFAS No. 143"), "Accounting for Asset Retirement Obligations."

SFAS No. 141 requires that the purchase method of accounting be used for all business combinations initiated or completed after June 30, 2001. SFAS No. 141 also specified criteria that intangible assets acquired in a purchase method business combination must be recognized and reported apart from goodwill. The adoption of SFAS No. 141 as of July 1, 2001 did not have an impact on the Company's consolidated financial statements.

SFAS No. 142 requires that goodwill as well as other intangible assets with indefinite lives not be amortized but tested annually for impairment. The adoption of SFAS No. 142 will not have an impact on the Company's consolidated financial statements.

SFAS No. 143 requires that the fair value of a liability for an asset retirement obligation be recorded in the period in which it is incurred and the corresponding cost capitalized by increasing the carrying amount of the related long-lived asset. The liability is accreted to its present value each period, and the capitalized cost is depreciated over the useful life of the related asset. If the liability is settled for an amount other than the recorded amount, a gain or loss is recognized. The standard is effective for the Company beginning in 2003, but earlier adoption is encouraged. Adoption of the standard will result in recording a cumulative effect of a change in accounting principle in the period of adoption. The Company has not yet determined the impact of this new standard or when the Company will adopt this new standard.

In August 2001, the FASB issued Statement of Financial Accounting Standards No. 144 ("SFAS No. 144"), "Accounting for the Impairment or Disposal of Long-Lived Assets." SFAS No. 144 addresses the financial accounting and reporting for the impairment or disposal of long-lived assets. SFAS No. 144 supersedes SFAS No. 121 but retains its fundamental provisions for the (a) recognition/measurement of impairment of long-lived assets to be held and used and (b) measurement of long-lived assets to be disposed of by sale. SFAS No. 144 also supersedes other pronouncements which currently do not affect the Company. SFAS No. 144 became effective for the Company beginning in 2002 and is not expected to have an impact on the Company's consolidated financial statements.

NOTE 2. ACQUISITIONS

Matrix Oil and Gas, Inc.

On July 10, 2001, the Company completed the acquisition of Matrix Oil & Gas, Inc.("Matrix"), an independent oil and gas company based in Covington, Louisiana. Under the merger agreement, Denbury paid a total of approximately $158.5 million, comprised of $99.3 million (63%) in cash and $59.2 million (37%) in the form of 6.6 million shares of Denbury's common stock. The cash portion of the purchase was funded with available cash and borrowings of $95.0 million from Denbury's bank credit facility. The purchase price was allocated to the net assets acquired based on estimated fair market values at the date of acquisition, with the predominant amount allocated to oil and gas properties. The Company allocated $30.0 million of the purchase price as unevaluated property to reflect the significant probable and possible reserves that were identified in the acquisition. In addition, the Company recorded a deferred income tax liability of $53.1 million to reflect the difference between the book and tax basis of the properties acquired. Although not expected, the purchase price allocation could still change as additional information becomes available. The Company reclassified $5.0 million of the unevaluated property cost to developed properties at year-end 2001 based on the results of drilling activity and the reserves added since July, leaving a balance of $25.0 million as of December 31, 2001 relating to Matrix. The Company's financial statements include the operations of Matrix from July 1, 2001.

In conjunction with the acquisition of Matrix, Denbury purchased commodity hedges to protect its investment. These hedges, in the form of price floors, covered nearly all of the forecasted production from the acquired properties for two and one-half years through the end of 2003 at floor prices ranging from $3.75 to $4.25 per MMBtu. Due to the falling natural gas prices in the latter half of 2001, the Company collected approximately $12.7 million on these hedges. Unfortunately, the price floors relating to 2002 and 2003 were purchased from Enron Corporation, which filed bankruptcy in December 2001. Denbury sold their bankruptcy claim against Enron in February 2002 for net proceeds of approximately $9.2 million. In total, Denbury collected approximately $21.9 million from the price floors relating to the Matrix acquisition, a net cash gain of approximately $3.9 million over the cost of the floors, but has suffered an opportunity loss in light of the drop in natural gas prices since the date of acquisition and the loss of the 2002 and 2003 hedges. See Note 7 to the consolidated financial statements for further information regarding the Company's hedging activities.

The following pro forma information gives effect to the acquisition of Matrix on the Company's historical consolidated statement of operations as if the merger had occurred at the beginning of the periods presented. The effects of other acquisitions in 2001 were not significant for inclusion in the pro forma presentation. Pro forma amounts are not necessarily indicative of actual results.

AMOUNTS IN THOUSANDS EXCEPT PER SHARE AMOUNTS	YEAR ENDED DECEMBER 31, 2001	2000
Revenues	$ 324,401	$ 214,473
Expenses	234,097	147,409
Net income	62,243	137,387
Income per common share:		
Basic	$ 1.18	$ 2.62
Diluted	1.16	2.60

CO2 Acquisition

On February 2, 2001, the Company purchased certain CO_2 reserves, production and associated assets from a division of Airgas, Inc. for $42 million. The cost of the acquisition was funded by available cash and $21 million borrowed under the Company's bank credit facility. The acquisition included ten producing CO_2 wells and production facilities located near Jackson, Mississippi, and a 183-mile, 20-inch pipeline that is currently transporting CO_2 to Denbury's tertiary recovery operation at Little Creek Field, as well as to other commercial customers.

Other 2001 Acquisitions

During 2001 the Company completed other minor acquisitions totaling approximately $5.0 million.

2000 Acquisitions

During the fourth quarter of 2000, the Company completed acquisitions totaling $56.5 million in the Thornwell, Porte Barre and Iberia Fields located in southwestern Louisiana. Approximately $10.0 million of these acquisition costs were initially recorded as unevaluated property costs at December 31, 2000. The Company also completed other minor acquisitions totaling $3.8 million during 2000.

1999 Acquisitions

During 1999, the Company completed acquisitions totaling $20.5 million, primarily comprised of a $12.3 million acquisition of a tertiary recovery oil field (Little Creek) in southern Mississippi and a $4.9 million acquisition of the King Bee Field, also in Mississippi.

NOTE 3. PROPERTY AND EQUIPMENT

Property and equipment at December 31, 2001 and 2000 consisted of the following:

AMOUNTS IN THOUSANDS	DECEMBER 31, 2001	DECEMBER 31, 2000
Oil and natural gas properties		
Proved properties	$ 1,098,263	$ 746,062
Unevaluated properties	44,521	13,810
Total	1,142,784	759,872
Accumulated depletion and depreciation	(518,760)	(452,358)
Net oil and natural gas properties	624,024	307,514
CO_2 properties	45,555	-
Accumulated depletion and depreciation	(1,572)	-
Net CO_2 properties	43,983	-
Net property and equipment	$ 668,007	$ 307,514

Unevaluated Oil and Natural Gas Properties Excluded From Depletion

Under full cost accounting, the Company may exclude certain unevaluated costs from the amortization base pending determination of whether proved reserves have been discovered or impairment has occurred. A summary of the unevaluated properties excluded from oil and natural gas properties being amortized at December 31, 2001 and 2000 and the year in which they were incurred follows:

	DECEMBER 31, 2001			DECEMBER 31, 2000			
	Costs Incurred During			Costs Incurred During			
AMOUNTS IN THOUSANDS	2001	2000	Total	2000	1999	1998	Total
Property acquisition costs	$ 34,195	$ 3,688	$ 37,883	$ 10,709	$ 750	$ 65	$ 11,524
Exploration costs	5,395	1,243	6,638	1,332	193	761	2,286
Total	$ 39,590	$ 4,931	$ 44,521	$ 12,041	$ 943	$ 826	$ 13,810

Costs are transferred into the amortization base on an ongoing basis as the projects are evaluated and proved reserves established or impairment determined. Pending determination of proved reserves attributable to the above costs, the Company cannot assess the future impact on the amortization rate. As of December 31, 2001, approximately $25.0 million of the total unevaluated property balance of $44.5 million related to the Matrix acquisition. These costs will be transferred into the amortization base as the undeveloped areas are tested. The Company anticipates that the majority of this activity should be completed over the next three to five years.

Capitalized Costs

Capitalized general and administrative costs that directly relate to exploration and development activities were $4.1 million, $3.2 million and $2.8 million for the years ended December 31, 2001, 2000 and 1999, respectively.

Amortization per BOE was $6.27, $4.62 and $4.17 for the years ended December 31, 2001, 2000 and 1999, respectively.

NOTE 4. NOTES PAYABLE AND LONG-TERM INDEBTEDNESS

AMOUNTS IN THOUSANDS	DECEMBER 31, 2001	2000
Senior bank loan	$ 140,870	$ 74,000
9% Senior Subordinated Notes due 2008	125,000	125,000
9% Series B Senior Subordinated Notes due 2008	75,000	-
Discount on 9% Series B Subordinated Notes due 2008	(6,101)	-
Total long-term debt	$ 334,769	$ 199,000

Senior Bank Loan

The Company has a credit facility with Bank of America, as agent for a group of nine other banks. The credit facility is secured by substantially all of the Company's producing oil and natural gas properties and matures on December 31, 2003. This credit facility has several restrictions including, among others: (i) a prohibition on the payment of dividends, (ii) a requirement for a minimum equity balance, (iii) a requirement to maintain positive working capital, as defined, (iv) a minimum interest coverage test and (v) a prohibition of most debt and corporate guarantees. The Company's bank credit facility provides for a semi-annual redetermination of the borrowing base on April 1st and October 1st. At the April 2001 redetermination, the Company's borrowing base was increased from $150 million to $200 million and further increased at the October 2001 redetermination to $220 million.

As of December 31, 2001, the Company had $140.9 million outstanding under the facility, at a weighted average interest rate of 4.2%, $370,000 of letters of credit outstanding and a borrowing base of $220 million. The next scheduled redetermination of the borrowing base will be as of April 1, 2002, based on December 31, 2001 assets and proved reserves.

Subordinated Debt

On February 26, 1998, Denbury Management Inc. ("DMI"), a wholly owned subsidiary of the Company at that time, issued $125 million in aggregate principal amount of 9% Senior Subordinated Notes due 2008 which require only semi-annual interest payments until maturity. In April 1999, DMI was merged into Denbury Resources Inc., which expressly assumed all liabilities of DMI, including the 9% Senior Subordinated Notes. These notes contain certain debt covenants, including covenants that limit (i) indebtedness, (ii) certain restricted payments including dividends, (iii) sale/leaseback transactions, (iv) transactions with affiliates, (v) liens, (vi) asset sales and (vii) mergers and consolidations. The net proceeds to the Company from the debt offering were approximately $121.8 million, before offering expenses.

During August 2001, Denbury issued an additional $75 million of subordinated debt in a private placement at 91.371% of face amount for an effective yield of 10.875%. The notes were issued under a separate indenture, but on terms substantially identical to the existing 9% Senior Subordinated Notes due 2008. The net proceeds to the Company were approximately $65.9 million. These notes were subsequently exchanged for a like principal amount of publicly registered notes.

Indebtedness Repayment Schedule

The Company's indebtedness as of December 31, 2001 is repayable as follows:

AMOUNTS IN THOUSANDS

YEAR	
2002	$ --
2003	140,870
2004	--
2005	--
2006	--
Thereafter (2008)	200,000
Total indebtedness	$ 340,870

NOTE 5. INCOME TAXES

The Company's income tax provision (benefit) is as follows:

AMOUNTS IN THOUSANDS	YEAR ENDED DECEMBER 31, 2001	2000	1999
Current income tax expense			
Federal	$ 614	$ 558	$ --
State	26	--	--
Total current income tax expense	640	558	--
Deferred income tax expense (benefit)			
Federal	24,184	(67,852)	--
State	--	--	--
Total deferred income tax expense (benefit)	24,184	(67,852)	--
Total income tax expense (benefit)	$ 24,824	$(67,294)	$ --

The Company's income tax benefit for 2000 is primarily the result of the elimination of the Company's valuation allowance on its net deferred tax assets as of December 31, 2000. The valuation allowance on the Company's net deferred tax assets was initially recorded at December 31, 1998 and the assets remained fully reserved at December 31, 1999, based upon management's belief that it was more likely than not that the Company would not be able to generate sufficient taxable income to realize the benefit of its net deferred tax assets. In reaching this conclusion, management considered both historical results and its expectations regarding future taxable income based on oil and gas pricing consistent with the Company's long-term forecasting and anticipated levels of capital spending. As a result of the near-term recovery of oil and natural gas prices that began in the latter part of 1999 and continued throughout 2000, the Company was able to generate net income for 2000 and taxable income that utilized approximately $27.2 million of the Company's net operating losses. Based on expectations at that time regarding current production levels, current expectations regarding near-term oil and gas prices, current hedging positions, anticipated capital expenditures, the estimated reversal of book and tax temporary differences, available tax planning strategies and the Company's expectations regarding future taxable income, management concluded that the valuation allowance on its net deferred tax assets was no longer necessary and at December 31, 2000 eliminated the entire valuation allowance. The Company's current income tax expense in 2000 and 2001 was for alternative minimum taxes that may not be offset by net operating losses.

At December 31, 2001, the Company had net operating loss carryforwards for U.S. federal income tax purposes of approximately $91.2 million and approximately $21.3 million for alternative minimum tax purposes. As a result of the acquisition of Matrix and other prior ownership changes, the utilization of some of the Company's net operating loss carryforwards is subject to limitations imposed by the Internal Revenue Code of 1986. However, the Company does not expect such limitations to have an effect on its ability to use its net operating loss carryforwards. The Company's net operating loss carryforwards are scheduled to expire as follows:

Amounts in Thousands	Income Tax	Alternative Minimum Tax
YEAR		
2018	$ 60,217	$ 5,407
2019	21,713	15,585
2020	8,023	193
2021	1,267	127

In 2001, the Company began to recognize a benefit for the amount of enhanced oil recovery credits earned from its tertiary recovery projects. The total amount of credits earned to date totals approximately $5.3 million. These credits begin to expire in 2020.

Deferred income taxes relate to temporary differences based on tax laws and statutory rates in effect at the December 31, 2001 and 2000 balance sheet dates. At December 31, 2001 and 2000, the Company's deferred tax assets and liabilities were as follows:

Amounts in Thousands	December 31, 2001	December 31, 2000
Deferred tax assets:		
Loss carryforwards	$ 33,751	$ 41,695
Property and equipment	--	26,144
Tax credit carryover	1,403	558
Enhanced oil recovery credit carryforwards	5,280	--
Total deferred tax assets	40,434	68,397
Deferred tax liabilities:		
Property and equipment	(48,978)	--
Derivative hedging contracts	(8,356)	--
Other	(533)	(545)
Total deferred tax liabilities	(57,867)	(545)
Total net deferred tax asset (liability)	$(17,433)	$ 67,852

The Company's income tax provision (benefit) varies from the amount that would result from applying the statutory income tax rate to income before income taxes as follows:

Amounts in Thousands	Year Ended December 31, 2001	2000	1999
Income tax provision (benefit) calculated using the statutory income tax rate	$ 28,481	$ 26,227	$ 1,615
State income taxes and other	1,623	1,616	(350)
Change in valuation allowance	-	(95,137)	(1,265)
Enhanced oil recovery credit	(5,280)	-	-
Total income tax expense (benefit)	$ 24,824	$ (67,294)	$ -

Note 6. Stockholders' Equity

Authorized

The Company is authorized to issue 100 million shares of common stock, par value $.001 per share, and 25 million shares of preferred stock, par value $.001 per share. The preferred shares may be issued in one or more series with rights and conditions determined by the board of directors.

1999 Sale of Stock to the Texas Pacific Group

In April 1999, the stockholders approved the sale of 18,552,876 shares of common stock to an affiliate of the Texas Pacific Group ("TPG") for $100 million or $5.39 per share. As a result of this transaction, TPG's ownership of the Company's outstanding common stock increased from approximately 32% to approximately 60%. The net proceeds from this sale of common stock of approximately $98.5 million were used to pay down the Company's revolving credit facility. At December 31, 2001, TPG's ownership of the Company's outstanding common stock had declined to approximately 52% primarily as a result of the shares issued in the Matrix acquisition.

Stock Option Plan

As of December 31, 2001, the Company had a total of 5,745,587 shares of common stock authorized for issuance pursuant to its Stock Option Plan, of which 268,609 shares were available for issuance. The board of directors of the Company has authorized an additional 1.6 million shares for this plan, subject to the approval of shareholders at the May 22, 2002 annual meeting. Under the terms of the plan, incentive and non-qualified options may be issued to officers, key employees and consultants. Options generally become exercisable over a four year vesting period with the specific terms of vesting determined by the board of directors at the time of grant. The options expire over terms not to exceed ten years from the date of grant, 90 days after termination of employment or permanent disability or one year after the death of the optionee. The options are granted at the fair market value at the time of grant, which is generally defined as the average closing price of the Company's shares of common stock for the ten trading days prior to issuance. The plan is administered by the Stock Option Committee of the Board.

Following is a summary of stock option activity during the years ended December 31, 2001, 2000 and 1999:

	YEAR ENDED DECEMBER 31, 2001		2000		1999	
	Number of Options	Weighted Average Price	Number of Options	Weighted Average Price	Number of Options	Weighted Average Price
Outstanding at beginning of year	3,802,122	$ 8.03	3,317,384	$ 8.66	1,890,531	$ 13.04
Granted	1,222,141	9.00	595,635	4.11	1,830,503	4.38
Exercised	(209,600)	5.00	(40,458)	4.60	-	-
Forfeited	(198,330)	8.53	(70,439)	6.70	(403,650)	9.78
Outstanding at end of year	4,616,333	$ 8.40	3,802,122	$ 8.03	3,317,384	$ 8.66
Exercisable at end of year	1,858,072	$ 9.49	1,310,382	$ 9.35	622,001	$ 9.39
Weighted average fair value of options granted		$ 5.19		$ 2.26		$ 2.56

The Company applies the intrinsic value method in accounting for options granted under the Stock Option Plan and accordingly no compensation cost is recognized. Had compensation expense been recognized based on the fair value of the options on the date they were granted, the Company's net income and net income per common share would have been reduced to the following pro forma amounts:

	Year Ended December 31, 2001	2000	1999
NET INCOME:			
As reported (thousands)	$ 56,550	$ 142,227	$ 4,614
Pro forma (thousands)	53,756	139,574	772
NET INCOME PER COMMON SHARE:			
As reported:			
Basic	$ 1.15	$ 3.10	$ 0.12
Diluted	1.12	3.07	0.12
Pro forma:			
Basic	$ 1.09	$ 3.05	$ 0.02
Diluted	1.09	3.05	0.02

The Company estimated the fair value of each option grant using the Black-Scholes option pricing method using the following weighted average assumptions:

	2001	2000	1999
Risk-free interest rate	4.64%	6.5%	4.7%
Expected life	5 years	5 years	5 years
Expected volatility	63.4%	55.0%	64.7%
Dividend yield	-	-	-

Notes to Consolidated Financial Statements

The following table summarizes information on the Company's stock options outstanding at December 31, 2001:

	Options Outstanding			Options Exercisable	
Range of Exercise Prices	Number of Options Outstanding at 12/31/01	Weighted Average Remaining Contractual Life	Weighted Average Exercise Price	Number of Options Exercisable at 12/31/01	Weighted Average Exercise Price
\$ 3.77 - \$ 5.50	1,894,433	7.2	\$ 4.18	630,456	\$ 4.25
5.51 - 8.00	335,060	5.4	6.75	251,499	6.71
8.01 - 11.50	1,333,230	8.4	9.20	198,830	9.92
11.51 - 14.50	601,938	4.8	13.38	601,938	13.38
14.51 - 22.25	451,672	5.8	18.35	175,349	18.43
\$ 3.77 - \$22.25	4,616,333	7.0	\$ 8.40	1,858,072	\$ 9.49

Stock Purchase Plan

The Company maintains a Stock Purchase Plan which authorizes the sale of up to 1,250,000 shares of common stock to all full-time employees. The board of directors of the Company has authorized an additional 500,000 shares for this plan, subject to the approval of shareholders at the May 22, 2002 annual meeting. As of December 31, 2001, the Company had 292,950 authorized shares remaining to issue under the plan. In accordance with the plan, the employees may contribute up to 10% of their base salary and the Company matches 75% of the employee contribution. The combined funds are used to purchase previously unissued common stock of the Company based on its current market value at the end of each quarter. The Company recognizes compensation expense for the 75% Company matching portion, which totaled \$666,000, \$560,000 and \$501,000 for the years ended December 31, 2001, 2000 and 1999, respectively. This plan is administered by the Stock Purchase Plan Committee of the Board.

401(k) Plan

T
he Company offers a 401(k) Plan to which employees may contribute tax deferred earnings subject to Internal Revenue Service limitations. The Company matches 75% of employee contributions up to an employee's contribution of 6% of their salary. This Company match becomes vested over a four year period. During 2001, 2000 and 1999, the Company made matching contributions of \$670,000, \$427,000 and \$239,000, respectively, to the 401(k) Plan.

NOTE 7. DERIVATIVE HEDGING CONTRACTS

The Company enters into various financial contracts to hedge its exposure to commodity price risk associated with anticipated future oil and natural gas production. These contracts have historically consisted of price ceilings and floors, collars and fixed price swaps.

Oil Hedges Historical Data

During March and April 1999, the Company entered into two no-cost contracts to hedge a portion of its oil production. The first contract was a fixed price swap for 3,000 Bbls/d from April through December 1999 at a price of $14.24 per Bbl. The second contract was a collar to hedge 3,000 Bbls/d from May 1999 through December 2000 with a floor price of $14.00 per Bbl and a ceiling price of $18.05 per Bbl. During 1999, the Company paid out approximately $8.6 million on these contracts, and during 2000 paid out $13.3 million relating to these oil collars.

During 2000, the Company purchased a $22.00 price floor on 2001 production covering 12,800 Bbls/d at an aggregate cost of $1.8 million. This contract covered approximately 75% of the anticipated 2001 oil production, excluding any anticipated production from acquisitions. During 2001, approximately $1.9 million was collected on this price floor.

During July 2001, the Company acquired a $21.00 price floor on 10,000 Bbls/d for 2002 production at an aggregate cost of approximately $4.7 million. This price floor covers approximately 60% of the Company's anticipated oil production for 2002.

Natural Gas Hedges Historical Data

As of January 1, 1999, the Company had no-cost financial contracts ("collars") in place that hedged a total of 40 MMcf/d through August 1999 and 30 MMcf/d thereafter through December 2000. The first set of contracts had a weighted average ceiling price of approximately $2.95 per MMBtu and the second set of contracts had a ceiling price of $2.58 per MMBtu. Both contracts had a price floor of $1.90 per MMBtu. During 1999, the Company paid out a net of $0.8 million on these contracts, including $0.7 million paid to retire a portion of the hedge. During 2000, the Company paid out $11.9 million relating to these same natural gas collars.

During 2000, the Company purchased a $2.80 price floor on 2001 production covering 37,500 MMBtu/d at an aggregate cost of $0.8 million. This contract covered approximately 75% of the anticipated 2001 natural gas production, excluding any anticipated production from acquisitions. During 2001, the Company collected $1.8 million on this price floor.

Concurrent with the acquisition of Thornwell Field, the Company purchased price floors for these predominately natural gas properties that were acquired in the fourth quarter of 2000. The price floors covered nearly all of the anticipated proven natural gas production from these properties for 2001 and 2002. These floors cost $2.5 million with varying volumes and price floors for each quarter for 2001 and 2002. During 2001, the Company collected $2.2 million from these price floors.

For the Matrix properties acquired in July 2001 (see also "Note 2"), the Company purchased price floors covering nearly all of the forecasted proven natural gas production through December 2003, with a minimum price of $4.25 per MMBtu for July 2001 through December 2002 and $3.75 per MMBtu for all of 2003, at a total cost of $18.0 million. Subsequent to the acquisition, natural gas prices began to decline and Denbury was paid approximately $12.7 million on these price floors during 2001. Unfortunately, the price floors relating to 2002 and 2003 were purchased from Enron, which filed bankruptcy in December 2001. The Company sold its bankruptcy claim against Enron in February 2002 for approximately $9.2 million. In total, the Company collected approximately $21.9 million from the price floors relating to the Matrix acquisition, a net cash gain of approximately $3.9 million, although the Company has suffered an opportunity loss in light of the drop in natural gas prices since the date of acquisition and the loss of the 2002 and 2003 hedges.

When Enron filed for bankruptcy during the fourth quarter of 2001, these Enron hedges ceased to qualify for hedge accounting treatment, which changed the accounting treatment for those hedges as of that point in time as required by SFAS No. 133. The result is that any future changes in the current market value of these assets must be reflected in the income statement and any remaining accumulated other comprehensive income at the time of the accounting change must be recognized over the original expected life of the hedges. To adjust the value of the Enron hedges down to the current market value, which was determined to be the amount that Denbury received when it sold the claims in February 2002, the Company took a pre-tax write down of $24.4 million in the fourth quarter of 2001. The Company also had a claim against Enron for production receivables relating to November 2001 natural gas production that was also sold in February 2002, which resulted in an overall total pre-tax loss on the Company's Enron related assets of $25.2 million. The after-tax balance in accumulated other comprehensive income related to the these Enron hedges was approximately $11.6 million at the point they no longer qualified for hedge accounting. Accordingly, this amount will be reclassified out of accumulated other comprehensive income to the income statement over the periods during which the hedges would have otherwise expired. The result is that the Company will recognize pre-tax income attributable to the Enron hedges during 2002 of approximately $13.4 million and pre-tax income during 2003 of approximately $5.1 million. The three year total pre-tax net loss on the Enron hedges will be approximately $5.9 million, which approximates the difference between the amount collected and paid for the Enron portion of the Matrix price floors.

Subsequent to the Enron bankruptcy, in December 2001, Denbury purchased additional hedges to protect against any further deterioration in natural gas prices. These have a floor price of $2.50 per MMBtu and an average ceiling price of approximately $4.15 per MMBtu and cover not only the anticipated gas production from the Matrix properties, but a substantial portion of the other natural gas production as well. Overall, these hedges, which were purchased from four different financial institutions, cover approximately 75% of the forecasted total 2002 natural gas production.

Summary of Hedging Results

During 1999, the Company paid out $8.6 million for losses on its oil hedges ($1.95 per Bbl) and $126,000 for losses on its natural gas hedges, and in addition expensed $672,000 in 1999 that was paid to buy out a portion of our natural gas hedges for the next year. During 2000, the Company paid out $13.3 million ($2.39 per Bbl) on its oil hedges and $11.9 million ($0.88 per Mcf) on its natural gas hedges. In contrast, during 2001, the Company collected $1.9 million ($0.31 per Bbl) on its oil hedges and $16.7 million ($0.54 per Mcf) on its natural gas hedges.

The following table lists all of the individual floors in place as of December 31, 2001.

Period	Volume Per Day	Floor Price
Oil Options or "puts" (Bbls/d):		
2002	10,000	$21.00
Gas Options or "puts" (MMBtu/d):		
Q1 - 2002	5,269	$3.65
Q2 - 2002	3,775	$3.40
Q3 - 2002	2,873	$3.38
Q4 - 20 02	2,135	$3.38

Period	Volume Per Day	Floor Price	Ceiling Price
Gas Price Collars (MMBtu/d):			
2002	20,000	$2.50	$4.10
2002	20,000	$2.50	$4.10
2002	25,000	$2.50	$4.20
2002	25,000	$2.50	$4.17

NOTE 8. COMPREHENSIVE INCOME

The following table presents comprehensive income for the year ended December 31, 2001.

Amounts in Thousands	YEAR ENDED DECEMBER 31, 2001	
Accumulated other comprehensive income - December 31, 2000		$ -
Net income	$ 56,550	
Other comprehensive income - net of tax		
Cumulative effect of change in accounting principle - January 1, 2001	1,012	
Reclassification adjustments related to derivative contracts	(1,012)	
Change in fair value of outstanding hedging positions	14,228	
Total other comprehensive income	14,228	14,228
Comprehensive income for the year ended December 31, 2001	$ 70,778	
Accumulated other comprehensive income - December 31, 2001		$ 14,228

The Company did not have any items that met the criteria of other comprehensive income, other than net income, for the years ended December 31, 2000 and 1999. Based on commodity prices as of December 31, 2001, the Company expects to reclassify pre-tax gains relating to hedges of $17.5 million ($11.0 million after tax) to the income statement over the next 12 months from the accumulated other comprehensive income balance at December 31, 2001.

NOTE 9. COMMITMENTS AND CONTINGENCIES

The Company has operating leases for the rental of office space, office equipment, and vehicles that totaled $1.6 million, $1.4 million and $1.2 million for the years ended December 31, 2001, 2000 and 1999, respectively. At December 31, 2001, long-term commitments for these items require the following future minimum rental payments:

AMOUNTS IN THOUSANDS

2002	$	1,719
2003		1,586
2004		1,570
2005		1,681
2006		1,670
Thereafter		4,302
Total lease commitments	$	12,528

The Company has future capital expenditure obligations related to field development costs that total $13.6 million over the next four years. None of the $13.6 million is required to be spent in 2002.

The Company is subject to various possible contingencies which arise primarily from interpretation of federal and state laws and regulations affecting the oil and natural gas industry. Such contingencies include differing interpretations as to the prices at which oil and natural gas sales may be made, the prices at which royalty owners may be paid for production from their leases, environmental issues and other matters. Although management believes that it has complied with the various laws and regulations, administrative rulings and interpretations thereof, adjustments could be required as new interpretations and regulations are issued. In addition, production rates, marketing and environmental matters are subject to regulation by various federal and state agencies.

The Company and its subsidiaries are involved in various lawsuits, claims and regulatory proceedings incidental to their businesses. In the opinion of management, the outcome of such matters will not have a material adverse effect on the Company's business, consolidated financial position, results of operations or cash flows.

NOTE 10. SUPPLEMENTAL INFORMATION

Significant Oil and Natural Gas Purchasers

Oil and natural gas sales are made on a day-to-day basis or under short-term contracts at the current area market price. The loss of any purchaser would not be expected to have a material adverse effect upon the Company's operations. For the year ended December 31, 2001, the Company sold 10% or more of its net production of oil and natural gas to the following purchasers: Conoco 14%, Hunt Refining 13%, EOTT Energy 12%, and Dynegy 12%. For the year ended December 31, 2000, four purchasers each accounted for more than 10% of the Company's net production of oil and natural gas and 67% in the aggregate. For the year ended December 31, 1999, four purchasers each accounted for more than 10% of the Company's net production of oil and natural gas and 68% in the aggregate.

Notes to Consolidated Financial Statements

Supplemental Cash Flow Information

Cash paid for interest and income taxes for each of the three years in the period ended December 31, 2001 is as follows:

	YEAR ENDED DECEMBER 31,		
AMOUNTS IN THOUSANDS	2001	2000	1999
Interest paid	$17,451	$13,936	$15,805
Income taxes paid	2,482	275	-

In connection with the Company's acquisition of Matrix, the Company had non-cash increases to property and equipment resulting from the issuance of the Company's common stock in the amount of $59.2 million and the recording of deferred taxes in the amount of $53.1 million.

Fair Value of Financial Instruments

The carrying amounts and estimated fair values of the Company's debt instruments at December 31, 2001 and 2000 are as follows:

	DECEMBER 31, 2001		DECEMBER 31, 2000	
AMOUNTS IN THOUSANDS	Carrying Amount	Estimated Fair Value	Carrying Amount	Estimated Fair Value
Senior bank debt	$ 140,870	$ 140,870	$ 74,000	$ 74,000
9% Senior Subordinated Notes due 2008	125,000	117,500	125,000	108,400
9% Series B Senior Subordinated Notes due 2008	68,899	70,500	-	-

As of December 31, 2001 and 2000, the carrying value of the Company's bank debt approximated fair value based on the fact that the Company's bank debt is subject to short-term floating interest rates that approximated the rates available to the Company at those periods. The fair values of the Company's senior subordinated notes is based on quoted market prices. The Company's other financial instruments are primarily cash, cash equivalents, short-term receivables and payables which approximate fair value due to the nature of the instrument and the relatively short maturities.

NOTE 11. SUPPLEMENTAL OIL AND NATURAL GAS DISCLOSURES (UNAUDITED)

Costs Incurred

The following table summarizes costs incurred and capitalized in oil and natural gas property acquisition, exploration and development activities. Property acquisition costs are those costs incurred to purchase, lease, or otherwise acquire property, including both undeveloped leasehold and the purchase of reserves in place. Exploration costs include costs of identifying areas that may warrant examination and examining specific areas that are considered to have prospects containing oil and natural gas reserves, including costs of drilling exploratory wells, geological and geophysical costs and carrying costs on undeveloped properties. Development costs are incurred to obtain access to proved reserves, including the cost of drilling development wells, and to provide facilities for extracting, treating, gathering and storing the oil and natural gas.

Costs incurred in oil and natural gas activities for the years ended December 31, 2001, 2000 and 1999 are as follows:

AMOUNTS IN THOUSANDS	Year Ended December 31, 2001	2000	1999
Property acquisitions:			
Proved (1)	$ 127,066	$ 50,285	$ 20,488
Unevaluated	37,051	11,741	1,283
Exploration	11,692	6,782	7,672
Development	151,366	65,213	25,524
Total costs incurred	$ 327,175	$ 134,021	$ 54,967

(1) Excludes deferred taxes recorded in the acquisition of Matrix of $53.1 million in 2001.

Oil and Natural Gas Operating Results

Results of operations from oil and natural gas producing activities excluding corporate overhead and interest costs for the years ended December 31, 2001, 2000 and 1999 are as follows:

AMOUNTS IN THOUSANDS	Year Ended December 31, 2001	2000	1999
Oil, natural gas and related product sales	$ 260,398	$ 204,636	$ 90,991
Gain (loss) on settlements of derivative contracts	18,654	(25,264)	(9,416)
Total revenues	279,052	179,372	81,575
Lease operating costs	55,049	38,676	26,029
Production taxes and marketing expenses	10,963	8,051	3,662
Depletion and depreciation	69,773	36,214	25,515
Loss on Enron related assets	25,164	-	-
Amortization of derivative contracts and other other non-cash hedging adjustments	7,816	-	-
Net operating income	110,287	96,431	26,369
Income tax provision (benefit)	35,526	(67,294)	-
Results of operations from oil and natural gas producing activities	$ 74,761	$ 163,725	$ 26,369

Oil and Natural Gas Reserves

Net proved oil and natural gas reserve estimates as of December 31, 2001 and 2000 were prepared by DeGolyer and MacNaughton, and as of December 31, 1999 were prepared by Netherland & Sewell, independent petroleum engineers located in Dallas, Texas. The reserves were prepared in accordance with guidelines established by the Securities and Exchange Commission and, accordingly, were based on existing economic and operating conditions. Oil and natural gas prices in effect as of the reserve report date were used without any escalation. (See "Standardized Measure of Discounted Future Net Cash Flows and Changes Therein Relating to Proved Oil and Natural Gas Reserves" below for a discussion of the effect of the different prices on reserve quantities and values.) Operating costs, production and ad valorem taxes and future development costs were based on current costs with no escalation.

Notes to Consolidated Financial Statements

There are numerous uncertainties inherent in estimating quantities of proved reserves and in projecting the future rates of production and timing of development expenditures. The following reserve data represents estimates only and should not be construed as being exact. Moreover, the present values should not be construed as the current market value of the Company's oil and natural gas reserves or the costs that would be incurred to obtain equivalent reserves. All of the reserves are located in the United States.

Estimated Quantities of Reserves

	YEAR ENDED DECEMBER 31,					
	2001		2000		1999	
	Oil (MBbl)	Gas (MMcf)	Oil (MBbl)	Gas (MMcf)	Oil (MBbl)	Gas (MMcf)
BALANCE AT BEGINNING OF YEAR	70,667	100,550	51,832	50,438	28,250	48,803
Revisions of previous estimates	4,344	(631)	4,078	8,271	83	418
Revisions due to price changes	(7,800)	(2,745)	412	1,905	15,884	75
Extensions and discoveries	2,308	66,448	2,746	25,593	4,383	8,910
Improved recovery (1)	1,667	-	16,466	5,613	-	-
Production	(6,197)	(31,112)	(5,555)	(13,533)	(4,413)	(10,201)
Acquisition of minerals in place	11,501	65,767	1,182	23,209	7,722	2,693
Sales of minerals in place	-	-	(494)	(946)	(77)	(260)
BALANCE AT END OF YEAR	76,490	198,277	70,667	100,550	51,832	50,438
PROVED DEVELOPED RESERVES						
Balance at beginning of year	52,353	77,358	32,767	41,635	20,357	44,995
Balance at end of year	54,722	169,897	52,353	77,358	32,767	41,635

(1) For years prior to December 31, 2000, the changes related to improved recovery were not material and were included with revisions of previous estimates.

Standardized Measure of Discounted Future Net Cash Flows and Changes Therein Relating to Proved Oil and Natural Gas Reserves

The Standardized Measure of Discounted Future Net Cash Flows and Changes Therein Relating to Proved Oil and Natural Gas Reserves ("Standardized Measure") does not purport to present the fair market value of the Company's oil and natural gas properties. An estimate of such value should consider, among other factors, anticipated future prices of oil and natural gas, the probability of recoveries in excess of existing proved reserves, the value of probable reserves and acreage prospects, and perhaps different discount rates. It should be noted that estimates of reserve quantities, especially from new discoveries, are inherently imprecise and subject to substantial revision.

Under the Standardized Measure, future cash inflows were estimated by applying year-end prices, adjusted for fixed and determinable escalations, to the estimated future production of year-end proved reserves. The product prices used in calculating these reserves have varied widely during the three year period. These prices have a significant impact on both the quantities and value of the proven reserves as the reduced oil price causes wells to reach the end of their economic life much sooner and can make certain proved undeveloped locations uneconomical, both of which reduce the reserves. The following representative oil and natural gas year-end prices were used in the Standardized Measure. These prices were adjusted by field to arrive at the appropriate corporate net price.

YEAR ENDED DECEMBER 31,

	2001	2000	1999
Oil (NYMEX)	$ 19.84	$ 26.80	$ 25.60
Natural Gas (NYMEX Henry Hub)	2.57	9.78	2.12

Future cash inflows were reduced by estimated future production and development costs based on year-end costs to determine pre-tax cash inflows. Future income taxes were computed by applying the statutory tax rate to the excess of pre-tax cash inflows over the Company's tax basis in the associated proved oil and natural gas properties. Tax credits and net operating loss carryforwards were also considered in the future income tax calculation. Future net cash inflows after income taxes were discounted using a 10% annual discount rate to arrive at the Standardized Measure.

	December 31,		
Amounts in Thousands	2001	2000	1999
Future cash inflows	$ 1,786,884	$ 2,609,306	$ 1,222,590
Future production costs	(655,363)	(600,195)	(370,385)
Future development costs	(178,546)	(95,068)	(69,642)
Future net cash flows before taxes	952,975	1,914,043	782,563
10% annual discount for estimated timing of cash flows	(378,647)	(755,074)	(319,693)
Discounted future net cash flows before taxes	574,328	1,158,969	462,870
Discounted future income taxes	(68,533)	(317,670)	(14,496)
STANDARDIZED MEASURE OF DISCOUNTED FUTURE NET CASH FLOWS	$ 505,795	$ 841,299	$ 448,374

The following table sets forth an analysis of changes in the Standardized Measure of Discounted Future Net Cash Flows from proved oil and natural gas reserves:

	Year Ended December 31,		
Amounts in Thousands	2001	2000	1999
BEGINNING OF YEAR	$ 841,299	$ 448,374	$ 115,019
Sales of oil and natural gas produced, net of production costs	(194,386)	(157,909)	(61,300)
Net changes in sales prices	(838,124)	281,181	262,660
Extensions and discoveries, less applicable future development and production costs	123,214	200,966	48,918
Improved recovery (1)	5,045	77,702	-
Previously estimated development costs incurred	64,072	20,623	8,402
Revisions of previous estimates, including revised estimates of development costs, reserves and rates of production	(13,290)	48,018	6,433
Accretion of discount	115,897	46,287	11,502
Acquisition of minerals in place	152,931	183,634	71,631
Sales of minerals in place	-	(4,403)	(395)
Net change in income taxes	249,137	(303,174)	(14,496)
END OF YEAR	$ 505,795	$ 841,299	$ 448,374

(1) For years prior to December 31, 2000, the changes related to improved recovery were not material and were included with revisions of previous estimates.

CO2 Reserves

At December 31, 2001, based on an engineering report prepared by DeGolyer and MacNaughton, the Company's CO_2 reserves, on a working interest basis, were estimated at 815 Bcf.

NOTE 12. CONDENSED CONSOLIDATING FINANCIAL INFORMATION

As of December 31, 2001, all of the Company's subordinated debt securities are fully and unconditionally guaranteed by Denbury Resources Inc.'s significant subsidiaries. Condensed consolidating financial information for Denbury Resources Inc. and its significant subsidiaries for the years ended December 31, 2001, 2000 and 1999 is as follows:

CONDENSED CONSOLIDATING BALANCE SHEETS

Amounts in Thousands	Denbury Resources Inc. (Parent and Issuer)	Guarantor Subsidiaries	Eliminations	Denbury Resources Inc. Consolidated
DECEMBER 31, 2001				
ASSETS				
Current assets	$ 98,182	$ 5,096	$ -	$ 103,278
Property and equipment	445,693	222,314	-	668,007
Investment in subsidiaries (equity method)	164,830	-	(164,830)	-
Other assets	15,684	3,019	-	18,703
Total assets	$ 724,389	$ 230,429	$ (164,830)	$ 789,988
LIABILITIES AND STOCKHOLDERS' EQUITY				
Current liabilities	$ 68,937	$ 11,001	$ -	$ 79,938
Long-term liabilities	306,284	54,598	-	360,882
Stockholders' equity	349,168	164,830	(164,830)	349,168
Total liabilities and stockholders' equity	$ 724,389	$ 230,429	$ (164,830)	$ 789,988
DECEMBER 31, 2000				
ASSETS				
Current assets	$ 89,235	$ 8,755	$ -	$ 97,990
Property and equipment	307,514	-	-	307,514
Investment in subsidiaries (equity method)	5,671	-	(5,671)	-
Other assets	51,080	795	-	51,875
Total assets	$ 453,500	$ 9,550	$ (5,671)	$ 457,379
LIABILITIES AND STOCKHOLDERS' EQUITY				
Current liabilities	$ 34,907	$ 3,879	$	$ - 38,786
Long-term liabilities	202,428	-	-	202,428
Stockholders' equity	216,165	5,671	(5,671)	216,165
Total liabilities and stockholders' equity	$ 453,500	$ 9,550	$ (5,671)	$ 457,379

CONDENSED CONSOLIDATING STATEMENTS OF OPERATIONS

Amounts in Thousands	Denbury Resources Inc. (Parent and Issuer)	Guarantor Subsidiaries	Eliminations	Denbury Resources Inc. Consolidated
YEAR ENDED DECEMBER 31, 2001				
Revenues	$ 261,678	$ 23,433	$ -	$ 285,111
Expenses	181,346	22,391	-	203,737
Income before the following:	80,332	1,042	-	81,374
Equity in net earnings of subsidiaries	653	-	(653)	-
Income (loss) before income taxes	80,985	1,042	(653)	81,374
Income tax provision	24,435	389	-	24,824
Net income (loss)	$ 56,550	$ 653	$ (653)	$ 56,550
YEAR ENDED DECEMBER 31, 2000				
Revenues	$ 180,538	$ 1,113	$ -	$ 181,651
Expenses	106,805	(87)	-	106,718
Income before the following:	73,733	1,200	-	74,933
Equity in net earnings of subsidiaries	1,200	-	(1,200)	-
Income before income taxes	74,933	1,200	(1,200)	74,933
Income tax benefit	(67,294)	-	-	(67,294)
Net income (loss)	$ 142,227	$ 1,200	$ (1,200)	$ 142,227
YEAR ENDED DECEMBER 31, 1999				
Revenues	$ 82,002	$ 988	$ -	$ 82,990
Expenses	78,109	267	-	78,376
Income before the following:	3,893	721	-	4,614
Equity in net earnings of subsidiaries	721	-	(721)	-
Income (loss) before income taxes	4,614	721	(721)	4,614
Income tax provision	-	-	-	-
Net income (loss)	$ 4,614	$ 721	$ (721)	$ 4,614

CONDENSED CONSOLIDATING STATEMENTS OF CASH FLOWS

Amounts in Thousands	Denbury Resources Inc. (Parent and Issuer)	Guarantor Subsidiaries	Eliminations	Denbury Resources Inc. Consolidated
YEAR ENDED DECEMBER 31, 2001				
Cash flow from operations	$ 154,034	$ 31,013	$ -	$ 185,047
Cash flow from investing activities	(294,253)	(24,577)	-	(318,830)
Cash flow from financing activities	134,986	-	-	134,986
Net increase (decrease) in cash flow	(5,233)	6,436	-	1,203
Cash, beginning of period	22,285	8	-	22,293
Cash, end of period	$ 17,052	$ 6,444	$ -	$ 23,496

CONDENSED CONSOLIDATING STATEMENTS OF CASH FLOWS (CONTINUED)

Amounts in Thousands	Denbury Resources Inc. (Parent and Issuer)	Guarantor Subsidiaries	Eliminations	Denbury Resources Inc. Consolidated
YEAR ENDED DECEMBER 31, 2000				
Cash flow from operations	$ 98,004	$ (2,032)	$ -	$ 95,972
Cash flow from investing activities	(133,040)	-	-	(133,040)
Cash flow from financing activities	47,593	-	-	47,593
Net increase (decrease) in cash flow	12,557	(2,032)	-	10,525
Cash, beginning of period	9,728	2,040	-	11,768
Cash, end of period	$ 22,285	$ 8	$ -	$ 22,293
YEAR ENDED DECEMBER 31, 1999				
Cash flow from operations	$ 40,376	$ 824	$ -	$ 41,200
Cash flow from investing activities	(58,295)	-	-	(58,295)
Cash flow from financing activities	26,814	-	-	26,814
Net increase in cash flow	8,895	824	-	9,719
Cash, beginning of period	833	1,216	-	2,049
Cash, end of period	$ 9,728	$ 2,040	$ -	$ 11,768

NOTE 13. UNAUDITED QUARTERLY INFORMATION

The following table presents unaudited summary financial information on a quarterly basis for 2001 and 2000:

In Thousands Except Per Share Amounts	March 31	June 30	Sept. 30	December 31
2001				
Revenues	$ 79,180	$ 67,407	$ 74,318	$ 64,206
Expenses	37,960	35,484	52,178	78,115
Net income	25,969	20,111	13,948	(3,478)
Net income per share:				
Basic	0.56	0.44	0.27	(0.07)
Diluted	0.55	0.42	0.26	(0.07)
Cash flow from operations (a)	54,982	45,194	48,670	37,955
Cash flow used for investing activities	70,391	44,891	139,993	63,555
Cash flow provided by financing activities	8,530	10,820	95,297	20,339

In Thousands Except Per Share Amounts	March 31	June 30	Sept. 30	December 31
2000				
Revenues	$ 35,767	$ 37,550	$ 44,749	$ 63,585
Expenses	24,232	23,927	25,629	32,930
Net income	11,515	13,603	19,039	98,070
Net income per share:				
Basic	0.25	0.30	0.42	2.14
Diluted	0.25	0.30	0.41	2.09
Cash flow from operations (a)	19,562	21,340	27,502	43,151
Cash flow used for investing activities	16,088	21,462	24,069	71,421
Cash flow provided by (used for) financing activities	308	(3,806)	(2,131)	53,222

(a) Exclusive of the net change in non-cash working capital balances.

Common Stock Trading Summary

The following table summarizes the high and low last reported sales prices on days in which there were trades of the Company's common stock on the New York Stock Exchange ("NYSE"), and on The Toronto Stock Exchange ("TSE") (as reported by such exchange) for each quarterly period for the last two fiscal years. The trades on the NYSE are reported in U.S. dollars and the TSE trades are reported in Canadian dollars. The Company plans to de-list from the TSE effective April 15, 2002.

As of February 1, 2002, to the best of the Company's knowledge, the common stock was held of record by approximately 1,200 holders, of which approximately 300 were U.S. residents holding approximately 90% of the outstanding common stock of the Company.

The Company has never paid any dividends on its common stock and currently does not anticipate paying any dividends in the foreseeable future. The Company is restricted from declaring or paying any cash dividends on its common stock under its bank loan agreement.

	NYSE (U.S. $)		TSE (CDN $)	
	HIGH	LOW	HIGH	LOW
2001				
First quarter	$ 12.00	$ 7.90	$ 19.00	$ 12.22
Second quarter	12.30	7.30	18.78	11.80
Third quarter	9.75	7.50	14.90	11.86
Fourth quarter	8.81	6.00	13.53	9.38
2001 annual	$ 12.30	$ 6.00	$ 19.00	$ 9.38
2000				
First quarter	$ 4.56	$ 3.75	$ 7.00	$ 4.80
Second quarter	6.38	3.75	9.50	5.00
Third quarter	8.44	4.31	12.65	5.80
Fourth quarter	11.44	6.31	16.80	9.30
2000 annual	$ 11.44	$ 3.75	$ 16.80	$ 4.80

EXHIBIT 21

LIST OF SUBSIDIARIES

NAME OF SUBSIDIARY	JURISDICTION OF INCORPORATION	STATUS
Tallahatchie Resources, Inc.	Texas	Wholly owned subsidiary of Denbury Resources Inc. - dormant
Denbury Marine, L.L.C.	Louisiana	Wholly owned subsidiary of Denbury Resources Inc. - marine company
Denbury Energy Services, Inc.	Texas	Wholly owned subsidiary of Denbury Resources Inc. - marketing company
Denbury Offshore, Inc.	Delaware	Wholly owned subsidiary of Denbury Resources Inc. - offshore oil and gas properties

EXHIBIT 23

INDEPENDENT AUDITORS' CONSENT

Denbury Resources Inc.

We consent to the incorporation by reference in Registration Statement Nos. 333-1006, 333-27995, 333-55999, 333-70485, 333-39172, 333-39218 and 333-63198 on Forms S-8, Registrations Statement No. 333-72106-01 on Form S-4, and Registration Statement No. 333-57382 on Form S-3 of Denbury Resources Inc. of our report dated February 25, 2002, appearing in this Annual Report on Form 10-K of Denbury Resources Inc. for the year ended December 31, 2001.

/s/ Deloitte & Touche LLP

Dallas, Texas
March 20, 2002