SECURITIES AND EXCHANGE COMMISSION
WASHINGTON, D.C. 20549
FORM 10-K

ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF
THE SECURITIES EXCHANGE ACT OF 1934
FOR THE FISCAL YEAR ENDED DECEMBER 31, 2002

COMMISSION FILE NUMBER 001-14039

CALLON PETROLEUM COMPANY
(Exact name of Registrant as specified in its charter)

DELAWARE	64-0844345
(State or other jurisdiction of incorporation or organization)	(I.R.S. Employer Identification No.)

200 NORTH CANAL STREET NATCHEZ, MISSISSIPPI 39120	(601) 442-1601
(Address of Principal Executive Offices)(Zip Code)	(Registrant's telephone number including area code)

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

TITLE OF EACH CLASS	NAME OF EXCHANGE ON WHICH REGISTERED
Convertible Exchangeable Preferred Stock, Series A, Par Value $.01 Per Share	New York Stock Exchange
Common Stock, Par Value $.01 Per Share	New York Stock Exchange
Preferred Stock Purchase Rights	New York Stock Exchange
11% Senior Subordinated Notes due 2005	New York Stock Exchange
10.25% Senior Subordinated Notes due 2004	New York Stock Exchange

Securities registered pursuant to Section 12(g) of the Act: NONE

Indicate by check mark whether the Registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the Registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days. Yes X. No .

Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K is not contained herein, and will not be contained, to the best of Registrant's knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10-K or any amendment to this Form 10-K. [X]

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

The aggregate market value of the voting and non-voting common equity held by nonaffiliates of the registrant was approximately $53,216,000 as of June 28, 2002, and $46,702,000 as of March 7, 2003 (based on the last reported sale price of such stock on the New York Stock Exchange on such dates).

As of March 7, 2003, there were 13,919,457 shares of the Registrant's Common Stock, par value $.01 per share, outstanding.

Document incorporated by reference: Portions of the definitive Proxy Statement of Callon Petroleum Company (to be filed no later than 120 days after December 31, 2002) relating to the Annual Meeting of Stockholders to be held on May 2, 2003, which is incorporated into Part III of this Form 10-K.

PART I.

ITEM 1 AND 2. BUSINESS AND PROPERTIES

OVERVIEW

Callon Petroleum Company has been engaged in the exploration, development, acquisition and production of oil and gas properties since 1950. Our properties are geographically concentrated primarily offshore in the Gulf of Mexico and onshore in Louisiana and Alabama. The public Company was incorporated under the laws of the state of Delaware in 1994 through the consolidation of a publicly traded limited partnership, a joint venture with a consortium of European institutional investors and an independent energy company owned by certain members of current management (the "Consolidation"). As used herein, the "Company," "Callon," "we," "us," and "our" refer to Callon Petroleum Company and its predecessors and subsidiaries unless the context requires otherwise.

In 1989, we began increasing our reserves through the acquisition of producing properties that were geologically complex, had (or were analogous to fields with) an established production history from stacked pay zones and were candidates for exploitation. We focused on reducing operating costs and implementing production enhancements through the application of technologically advanced production and recompletion techniques.

Over the past seven years, we have also placed emphasis on the acquisition of acreage with exploration and development drilling opportunities in the Gulf of Mexico Shelf area. We acquired an infrastructure of production platforms, gathering systems and pipelines to minimize development expenditures of these drilling opportunities. We also joined with other industry partners, primarily Murphy Exploration and Production, Inc., ("Murphy"), to explore federal offshore blocks acquired in the Gulf of Mexico. Our areas of exploration include the Gulf of Mexico Deepwater area (generally 900 to 5,500 feet of water).

We ended the year 2002 with estimated net proved reserves of 236 billion cubic feet of natural gas equivalent ("Bcfe"). This represents a decrease of 22% from 2001 year-end estimated net proved reserves of 303 Bcfe.

The major focus of our future operations is expected to continue to be the exploration for and development of oil and gas properties, primarily in the Gulf of Mexico.

AVAILABILITY OF REPORTS

All of our annual reports on Form 10-K, quarterly reports on Form 10-Q, current reports on Form 8-K, and amendments to such reports as well as other filings we make pursuant to Section 13(a) and 15(d) of the Securities Exchange Act of 1934 are available free of charge on our Internet website. The address of our Internet website is www.callon.com. Our SEC filings are available on our website as soon as they are posted to the EDGAR database on the SEC's website.

BUSINESS STRATEGY

Our goal is to increase shareholder value by increasing our reserves, production, cash flow and earnings. We seek to achieve these goals through the following strategies:

- Focus on Gulf of Mexico exploration with a balance between shelf and deepwater areas using the latest available technology.

- Aggressively explore our existing prospect inventory.

- Replenish our prospect inventory with increasing emphasis on prospect generation.

- Achieve moderate increases in current production levels through continued shelf exploration.

- Achieve significant increases in longer-term production levels through development of deepwater discoveries and ongoing deepwater exploration.

EXPLORATION AND DEVELOPMENT ACTIVITIES

Capital expenditures for exploration and development costs related to oil and gas properties totaled approximately $61.9 million in 2002. We incurred approximately $24.4 million in the Gulf of Mexico Shelf area, with approximately $9.7 million related to the Mobile 952/953/955 acceleration project. The Gulf of Mexico Deepwater area expenditures ($24.6 million) accounted for the remainder of the total capital expended, along with $660,000 incurred in leasehold and seismic acquisition costs and $15.2 million of interest and general and administrative costs allocable directly to exploration and development projects. The Gulf of Mexico Deepwater area expenditures were incurred primarily in the production facility fabrication for our Medusa discovery.

As a result of drilling successes in the Gulf of Mexico Deepwater area, we are faced with increased costs to develop these significant proved undeveloped reserves. A large portion of these future development costs will be incurred in 2003 and beyond. While management believes that current availability under our existing credit facilities along with current cash flows are expected to meet the needs of these development costs, no assurances can be made that we will be able to fund these development costs.

SEC REVIEW OF PROVED RESERVES

In October 2002, we received a letter from the SEC requesting supplemental information concerning our operations in the Gulf of Mexico. We believe that a similar letter was sent to other oil and gas companies with off-shore operations. We responded to the SEC's letter on October 18, 2002.

On February 21, 2003, we received another letter from the SEC requesting additional information about the procedures we used to classify our offshore reserves as "proved" in our Form 10-K for our fiscal year ended December 31, 2001. The letter also questions the procedures used to classify reserves at our Boomslang property as proved undeveloped reserves at year end 1998. In 2002, we drilled a development well which caused us to reduce our estimated reservoir volumes at our Boomslang property (and record a downward revision of our estimates of the reserves attributable to such property at December 31, 2002) to such an extent that the partners determined that the risk of further development was not economic. The staff of the SEC has asked Callon to restate its financial statements for fiscal years 2000 and 2001 to remove the reserves attributable to Boomslang as proved. We responded to the SEC's second letter on March 13, 2003.

We have reviewed the SEC comments with our independent petroleum reserve engineers, Huddleston & Co., Inc., Houston, Texas. Both Huddleston & Co. and Callon believe that our proved reserves were properly classified in accordance with SEC definitions and industry practices. The Company believes the reserve revision has no effect on prior year financial statements as it represents a change in estimate. If the SEC requires us to retroactively classify Boomslang as an unproved property through December, 2002, we would be required to restate our financial position, results of operations, and supplemental oil and gas reserve data from 1998 through 2002.

Based on our discussions with others in the oil and gas business, we believe that the SEC is reviewing generally the procedures used by reserve engineers to classify oil and gas reserves as proved in the

deepwater areas of the Gulf of Mexico. In particular, the SEC appears to indicate that it is not appropriate to classify reserves as proved without conducting a "flow test." It has not been our practice to conduct a flow test on our deepwater properties prior to classifying the reserves as proved. We believe, and have been advised by Huddleston & Co., that our procedures for classifying our deepwater reserves as proved are in accordance with SEC rules and industry practices.

The SEC has asked us, and we have provided substantial detail, about our proved reserves, including the detailed reserve report. At this point, we cannot predict the ultimate outcome of the SEC's review of our proved reserves. With respect to our deepwater projects other than Boomslang, we believe that the outcome of the SEC's review of practices in the oil and gas industry for classifying deepwater reserves as proved should not affect us materially differently than other similarly situated oil and gas companies with deepwater projects. With respect to Boomslang, we believe that reserves attributable to the project were properly classified as proved at year end 1998, 1999, 2000 and 2001, and that no restatement of our financial statements is required as this revision to our Boomslang reserves in 2002 represented a change in estimates of our proved reserves. We cannot make any assurances, however, that the SEC will ultimately agree with this position.

RISK FACTORS

DECREASE IN OIL AND GAS PRICES MAY ADVERSELY AFFECT OUR RESULTS OF OPERATIONS AND FINANCIAL CONDITION. Our success is highly dependent on prices for oil and gas, which are extremely volatile. Any substantial or extended decline in the price of oil or gas would have a material adverse effect on us. Oil and gas markets are both seasonal and cyclical. The prices of oil and gas depend on factors we cannot control such as weather, economic conditions, and levels of production, actions by OPEC and other countries and government actions. Prices of oil and gas will affect the following aspects of our business:

- our revenues, cash flows and earnings;
- the amount of oil and gas that we are economically able to produce;
- our ability to attract capital to finance our operations and the cost of the capital;
- the amount we are allowed to borrow under our senior credit facility;
- the value of our oil and gas properties; and
- the profit or loss we incur in exploring for and developing our reserves.

UNLESS WE ARE ABLE TO REPLACE RESERVES WHICH WE HAVE PRODUCED, OUR CASH FLOWS AND PRODUCTION WILL DECREASE OVER TIME. Our future success depends upon our ability to find, develop and acquire oil and gas reserves that are economically recoverable. As is generally the case for Gulf properties, our producing properties usually have high initial production rates, followed by a steep decline in production. As a result, we must continually locate and develop or acquire new oil and gas reserves to replace those being depleted by production. We must do this even during periods of low oil and gas prices when it is difficult to raise the capital necessary to finance these activities and during periods of high operating costs when it is expensive to contract for drilling rigs and other equipment and personnel necessary to explore for oil and gas. Without successful exploration or acquisition activities, our reserves, production and revenues will decline rapidly. We cannot assure you that we will be able to find and develop or acquire additional reserves at an acceptable cost.

A SIGNIFICANT PART OF THE VALUE OF OUR PRODUCTION AND RESERVES IS CONCENTRATED IN A SMALL NUMBER OF OFFSHORE PROPERTIES, AND ANY PRODUCTION PROBLEMS OR INACCURACIES IN RESERVE ESTIMATES RELATED TO THOSE PROPERTIES WOULD ADVERSELY IMPACT OUR BUSINESS. During 2002, 49% of our daily production came from two of our properties in the Gulf of Mexico. Moreover, one property accounted for 33% of our production during this period. If mechanical problems, storms or other events curtailed a substantial

portion of this production, our results of operations would be adversely affected. In addition, at December 31, 2002, most of our proved reserves were located in five fields in the Gulf of Mexico, with approximately 93% of our total net proved reserves attributable to these properties. If the actual reserves associated with any one of these producing properties are less than our estimated reserves, our results of operations and financial condition could be adversely affected.

OUR FOCUS ON EXPLORATION PROJECTS INCREASES THE RISKS INHERENT IN OUR OIL AND

GAS ACTIVITIES. Our business strategy focuses on replacing reserves through exploration, where the risks are greater than in acquisitions and development drilling. Although we have been successful in exploration in the past, we cannot assure you that we will continue to increase reserves through exploration or at an acceptable cost. Additionally, we are often uncertain as to the future costs and timing of drilling, completing and producing wells. Our drilling operations may be curtailed, delayed or canceled as a result of a variety of factors, including:

o unexpected drilling conditions;

o pressure or inequalities in formations;

o equipment failures or accidents;

o adverse weather conditions;

o compliance with governmental requirements; and

o shortages or delays in the availability of drilling rigs and the delivery of equipment.

BECAUSE WE DO NOT CONTROL, AND DO NOT OPERATE, ALL OF OUR PROPERTIES, ESPECIALLY OUR DEEPWATER PROPERTIES, WE HAVE LIMITED INFLUENCE OVER THEIR DEVELOPMENT. Our lack of control could result in the following:

o the operator may initiate exploration or development on a faster or slower pace than we prefer;

o the operator may propose to drill more wells or build more facilities on a project than we have funds for or that we deem appropriate, which may mean that we are unable to participate in the project or share in the revenues generated by the project even though we paid our share of exploration costs; and

o if an operator refuses to initiate a project, we may be unable to pursue the project.

Any of these events could materially reduce the value of our properties.

OUR DEEPWATER OPERATIONS HAVE SPECIAL OPERATIONAL RISKS THAT MAY NEGATIVELY AFFECT THE VALUE OF THOSE ASSETS. Drilling operations in the deepwater area are by their nature more difficult and costly than drilling operations in shallow water. Deepwater drilling operations require the application of more advanced drilling technologies, involving a higher risk of technological failure and usually have significantly higher drilling costs than shallow water drilling operations. Deepwater wells are completed using sub sea completion techniques that require substantial time and the use of advanced remote installation equipment. These operations involve a high risk of mechanical difficulties and equipment failures that could result in significant cost overruns.

In deepwater, the time required to commence production following a discovery is much longer than in shallow water and on-shore. Our deepwater discoveries and prospects will require the construction of expensive production facilities and pipelines prior to the beginning of production. We cannot estimate the costs and timing of the construction of these facilities with certainty, and the accuracy of our estimates will be affected by a number of factors beyond our control, including the following:

o decisions made by the operators of our deepwater wells;

o the availability of materials necessary to construct the facilities;

o the proximity of our discoveries to pipelines; and

o the price of oil and natural gas.

Delays and cost overruns in the commencement of production will affect the value of our deepwater prospects and the discounted present value of reserves attributable to those prospects.

Competitive industry conditions may negatively affect our ability to conduct operations. We operate in the highly competitive areas of oil and gas exploration, development and production. We compete for the purchase of leases in the Gulf of Mexico from the U. S. government and from other oil and gas companies. These leases include exploration prospects as well as properties with proved reserves. Factors that affect our ability to compete in the marketplace include:

- our access to the capital necessary to drill wells and acquire properties;
- our ability to acquire and analyze seismic, geological and other information relating to a property;
- our ability to retain the personnel necessary to properly evaluate seismic and other information relating to a property;
- the location of, and our ability to access, platforms, pipelines and other facilities used to produce and transport oil and gas production;
- the standards we establish for the minimum projected return on an investment of our capital; and
- the availability of alternate fuel sources.

Our competitors include major integrated oil companies, substantial independent energy companies, and affiliates of major interstate and intrastate pipelines and national and local gas gatherers, many of which possess greater financial, technological and other resources than we do.

OUR COMPETITORS MAY USE SUPERIOR TECHNOLOGY, WHICH WE MAY BE UNABLE TO AFFORD OR WHICH WOULD REQUIRE COSTLY INVESTMENT BY US IN ORDER TO COMPETE. Our industry is subject to rapid and significant advancements in technology, including the introduction of new products and services using new technologies. As our competitors use or develop new technologies, we may be placed at a competitive disadvantage, and competitive pressures may force us to implement new technologies at a substantial cost. In addition, our competitors may have greater financial, technical and personnel resources that allow them to enjoy technological advantages and may in the future allow them to implement new technologies before we can. We cannot be certain that we will be able to implement technologies on a timely basis or at a cost that is acceptable to us. One or more of the technologies that we currently use or that we may implement in the future may become obsolete, and we may be adversely affected. For example, marine seismic acquisition technology has been characterized by rapid technological advancements in recent years, and further significant technological developments could substantially impair our 3-D seismic data's value.

WE MAY NOT BE ABLE TO REPLACE OUR RESERVES OR GENERATE CASH FLOWS IF WE ARE UNABLE TO RAISE CAPITAL. WE WILL BE REQUIRED TO MAKE SUBSTANTIAL CAPITAL EXPENDITURES TO DEVELOP OUR EXISTING RESERVES, AND TO DISCOVER NEW OIL AND GAS RESERVES. Historically, we have financed these expenditures primarily with cash from operations, proceeds from bank borrowings and proceeds from the sale of debt and equity securities. See "Management's Discussion and Analysis of Financial Condition and Results of Operations -- Liquidity and Capital Resources" for a discussion of our capital budget. We cannot assure you that we will be able to raise capital in the future. We also make offers to acquire oil and gas properties in the ordinary course of our business. If these offers are accepted, our capital needs may increase substantially.

We expect to continue using our senior credit facility to borrow funds to supplement our available cash. The amount we may borrow under our senior credit facility may not exceed a borrowing base determined by the lenders based on their projections of our future production, future production costs, taxes, commodity prices and any other factors deemed relevant by our lenders. We cannot control the assumptions the lenders use to calculate our borrowing base. The lenders may, without our consent, adjust the borrowing base semiannually or in situations where we purchase or sell assets or issue debt securities. If our borrowings under the senior credit facility exceed the borrowing base, the lenders may require that we repay the excess. If this were to occur, we might have to sell assets or seek financing from other sources. Sales of assets could further reduce the amount of our borrowing base. We cannot assure you that we would be successful in selling assets or arranging substitute financing. If we were not able to repay borrowings under our senior credit facility to reduce the outstanding amount to less than the borrowing base, we would be in default under our senior credit facility. For a description of our senior credit facility and its principal terms and conditions, see "Management's Discussion and Analysis of Financial Condition and Results of Operations -- Liquidity and Capital Resources."

OUR RESERVE INFORMATION REPRESENTS ESTIMATES THAT MAY TURN OUT TO BE INCORRECT IF THE ASSUMPTIONS UPON WHICH THESE ESTIMATES ARE BASED ARE INACCURATE. ANY MATERIAL INACCURACIES IN THESE RESERVE ESTIMATES OR UNDERLYING ASSUMPTIONS WILL MATERIALLY AFFECT THE QUANTITIES AND PRESENT VALUE OF OUR RESERVES. The process of estimating oil and gas reserves is complex. It requires interpretations of available technical data and various assumptions, including assumptions relating to economic factors. Any significant inaccuracies in these interpretations or assumptions could materially affect the estimated quantities and present value of reserves shown in this annual report.

In order to prepare these estimates, we must project production rates and the timing of development expenditures. The assumptions regarding the timing and costs to commence production from our deepwater wells used in preparing our reserves are often subject to revisions over time as described under "our deepwater operations have special operational risks that may negatively affect the value of those assets." We must also analyze available geological, geophysical, production and engineering data, the extent, quality and reliability of which can vary. The process also requires economic assumptions, such as oil and gas prices, drilling and operating expenses, capital expenditures, taxes and availability of funds. Therefore, estimates of oil and gas reserves are inherently imprecise.

Actual future production, oil and gas prices, revenues, taxes, development expenditures, operating expenses and quantities of recoverable oil and gas reserves most likely will vary from our estimates. Any significant variance could materially affect the estimated quantities and present value of reserves shown in this report. In addition, we may adjust estimates of proved reserves to reflect production history, results of exploration and development, prevailing oil and gas prices and other factors, many of which are beyond our control.

You should not assume that the present value of future net cash flows from our proved reserves referred to in this report is the current market value of our estimated oil and gas reserves. In accordance with SEC requirements, we generally base the estimated discounted future net cash flows from our proved reserves on prices and costs on the date of the estimate. Actual future prices and costs may differ materially from those used in the present value estimate.

Information about reserves constitutes forward-looking information. See "Forward-Looking Statements" for information regarding forward-looking information. The discounted present value of our oil and gas reserves is prepared in accordance with guidelines established by the SEC. A purchaser of reserves would use numerous other factors to value our reserves. The discounted present value of reserves, therefore, does not represent the fair market value of those reserves.

On December 31, 2002, approximately 81.4% of the discounted present value of our estimated net proved reserves were proved undeveloped. Proved undeveloped oil volumes represented 96% of total proved oil reserves. Substantially all of these proved undeveloped reserves were attributable to our deepwater properties. Development of these properties is subject to additional risks as described above.

THE SEC MAY REQUIRE US TO BOOK RESERVES AS PROVED IN A MANNER THAT DIFFERS FROM OUR HISTORICAL PRACTICES AND CURRENT INDUSTRY STANDARDS, AND WHICH MAY RESULT IN A SIGNIFICANT DOWNWARD REVISION OF OUR PROVED RESERVES. As discussed above, in October 2002 and February 2003, we received letters from the SEC regarding our Annual Report on Form 10-K for the year ended December 31, 2001 requesting supplemental information concerning our operations in the Gulf of Mexico. The comment letters requested information about the procedures we used to classify our deepwater reserves as proved and requested that our financials be restated to reflect the removal of the Boomslang reserves as proved for all prior periods during which such reserves were reported as proved. We have reviewed the SEC

comments with our independent petroleum reserve engineers, Huddleston & Co., Inc. of Houston, Texas. Both Huddleston & Co and Callon believe that such reserves were properly classified as proved. However, if the SEC decides to question our other deepwater properties and these reserves are ultimately required to be reclassified as not proved; our proved reserves will be materially reduced. If the SEC requires us to retroactively classify Boomslang as an unproved property through December, 2002, we would be required to restate our financial position, results of operations, and supplemental oil and gas reserve data from 1998 through 2002. A material reduction in our proved reserves could have a material adverse effect on our financial condition and results of operations.

WEATHER, UNEXPECTED SUBSURFACE CONDITIONS, AND OTHER UNFORESEEN OPERATING HAZARDS MAY ADVERSELY IMPACT OUR ABILITY TO CONDUCT BUSINESS. There are many operating hazards in exploring for and producing oil and gas, including:

- our drilling operations may encounter unexpected formations or pressures, which could cause damage to equipment or personal injury;

- we may experience equipment failures which curtail or stop production; and

- we could experience blowouts or other damages to the productive formations that may require a well to be re-drilled or other corrective action to be taken.

In addition, any of the foregoing may result in environmental damages for which we will be liable. Moreover, a substantial portion of our operations are offshore and are subject to a variety of risks peculiar to the marine environment such as capsizing, collisions, hurricanes and other adverse weather conditions. These conditions can cause substantial damage to facilities and interrupt production. Offshore operations are also subject to more extensive governmental regulation.

We cannot assure you that we will be able to maintain adequate insurance at rates we consider reasonable to cover our possible losses from operating hazards. The occurrence of a significant event not fully insured or indemnified against could materially and adversely affect our financial condition and results of operations.

WE MAY NOT HAVE PRODUCTION TO OFFSET HEDGES; BY HEDGING, WE MAY NOT BENEFIT FROM PRICE INCREASES. Part of our business strategy is to reduce our exposure to the volatility of oil and gas prices by hedging a portion of our production. In a typical hedge transaction, we will have the right to receive from the other parties to the hedge the excess of the fixed price specified in the hedge over a floating price based on a market index, multiplied by the quantity hedged. If the floating price exceeds the fixed price, we are required to pay the other parties this difference multiplied by the quantity hedged. We are required to pay the difference between the floating price and the fixed price when the floating price exceeds the fixed price regardless of whether we have sufficient production to cover the quantities specified in the hedge. Significant reductions in production at times when the floating price exceeds the fixed price could require us to make payments under the hedge agreements even though such payments are not offset by sales of production. Hedging will also prevent us from receiving the full advantage of increases in oil or gas prices above the fixed amount specified in the hedge. See "Quantitative and Qualitative Disclosures About Market Risks" for a discussion of our hedging practices.

COMPLIANCE WITH ENVIRONMENTAL AND OTHER GOVERNMENT REGULATIONS COULD BE COSTLY AND COULD NEGATIVELY IMPACT PRODUCTION. Our operations are subject to numerous laws and regulations governing the operation and maintenance of our facilities and discharge of materials into the environment or otherwise relating to environmental protection. For a discussion of the material regulations applicable to us, see "Federal Regulations," "State Regulations," and "Environmental Regulations." These laws and regulations may:

- require that we acquire permits before commencing drilling;
- restrict the substances that can be released into the environment in connection with drilling and production activities;
- limit or prohibit drilling activities on protected areas such as wetlands or wilderness areas; and
- require remedial measures to mitigate pollution from former operations, such as dismantling abandoned production facilities.

Under these laws and regulations, we could be liable for personal injury and clean-up costs and other environmental and property damages, as well as administrative, civil and criminal penalties. We maintain limited insurance coverage for sudden and accidental environmental damages. We do not believe that insurance coverage for environmental damages that occur over time is available at a reasonable cost. Also, we do not believe that insurance coverage for the full potential liability that could be caused by sudden and accidental environmental damages is available at a reasonable cost. Accordingly, we may be subject to liability or we may be required to cease production from properties in the event of environmental damages.

FACTORS BEYOND OUR CONTROL AFFECT OUR ABILITY TO MARKET PRODUCTION AND OUR FINANCIAL RESULTS. The ability to market oil and gas from our wells depends upon numerous factors beyond our control. These factors include:

- the extent of domestic production and imports of oil and gas;
- the proximity of the gas production to gas pipelines;
- the availability of pipeline capacity;
- the demand for oil and gas by utilities and other end users;
- the availability of alternative fuel sources;
- the effects of inclement weather;
- state and federal regulation of oil and gas marketing; and
- federal regulation of gas sold or transported in interstate commerce.

Because of these factors, we may be unable to market all of the oil or gas we produce. In addition, we may be unable to obtain favorable prices for the oil and gas we produce.

IF OIL AND GAS PRICES DECREASE, WE MAY BE REQUIRED TO TAKE WRITEDOWNS. We may be required to writedown the carrying value of our oil and gas properties when oil and gas prices are low or if we have substantial downward adjustments to our estimated net proved reserves, increases in our estimates of development costs or deterioration in our exploration results. Under the full cost method which we use to account for our oil and gas properties, the net capitalized costs of our oil and gas properties may not exceed the present value, discounted at 10%, of future net cash flows from estimated net proved reserves, using period end oil and gas prices or prices as of the date of our auditor's report, plus the lower of cost or fair market value of our unproved properties. If net capitalized costs of our oil and gas properties exceed this limit, we must charge the amount of the excess to earnings. This type of charge will not affect our cash flows, but will reduce the book value of our stockholders' equity. We review the carrying value of our properties quarterly, based on prices in effect as of the end of each quarter or at the time of reporting our

results. Once incurred, a writedown of oil and gas properties is not reversible at a later date, even if prices increase.

FORWARD-LOOKING STATEMENTS

In this report, we have made many forward-looking statements. We cannot assure you that the plans, intentions or expectations upon which our forward-looking statements are based will occur. Our forward-looking statements are subject to risks, uncertainties and assumptions, including those discussed elsewhere in this report. Forward-looking statements include statements regarding:

- our oil and gas reserve quantities, and the discounted present value of these reserves;
- the amount and nature of our capital expenditures;
- drilling of wells;
- the timing and amount of future production and operating costs;
- business strategies and plans of management; and
- prospect development and property acquisitions.

Some of the risks, which could affect our future results and could cause results to differ materially from those expressed in our forward-looking statements include:

- general economic conditions;
- the volatility of oil and natural gas prices;
- the uncertainty of estimates of oil and natural gas reserves;
- the impact of competition;
- the availability and cost of seismic, drilling and other equipment;
- operating hazards inherent in the exploration for and production of oil and natural gas;
- difficulties encountered during the exploration for and production of oil and natural gas;
- difficulties encountered in delivering oil and natural gas to commercial markets;
- changes in customer demand and producers' supply;
- the uncertainty of our ability to attract capital;
- compliance with, or the effect of changes in, the extensive governmental regulations regarding the oil and natural gas business;
- actions of operators of our oil and gas properties; and

- o weather conditions.

The information contained in this report, including the information set forth under the heading "Risk Factors," identifies additional factors that could affect our operating results and performance. We urge you to carefully consider these factors and the other cautionary statements in this report. Our forward-looking statements speak only as of the date made, and we have no obligation to update these forward-looking statements.

CORPORATE OFFICES

Our headquarters are located in Natchez, Mississippi, in approximately 51,500 square feet of owned space, with a field office in Houston, Texas. We also maintain owned or leased field offices in the area of the major fields in which we operate properties or have a significant interest. Replacement of any of our leased offices would not result in material expenditures by us as alternative locations to our leased space are anticipated to be readily available.

EMPLOYEES

We had 100 employees as of December 31, 2002, none of whom are currently represented by a union. We believe that we have good relations with our employees. We employ nine petroleum engineers and seven petroleum geoscientists.

FEDERAL REGULATIONS

SALES OF NATURAL GAS. Effective January 1, 1993, the Natural Gas Wellhead Decontrol Act deregulated prices for all "first sales" of natural gas. Thus, all sales of gas by the Company may be made at market prices, subject to applicable contract provisions.

TRANSPORTATION OF NATURAL GAS. The rates, terms and conditions applicable to the interstate transportation of natural gas by pipelines are regulated by the Federal Energy Regulatory Commission ("FERC") under the Natural Gas Act ("NGA"), as well as under section 311 of the Natural Gas Policy Act ("NGPA"). Since 1985, the FERC has implemented regulations intended to make natural gas transportation more accessible to gas buyers and sellers on an open-access, non-discriminatory basis.

The FERC has announced several important transportation-related policy statements and rule changes, including a statement of policy and final rule issued February 25, 2000 concerning alternatives to its traditional cost-of-service rate-making methodology to establish the rates interstate pipelines may charge for their services. The final rule revises FERC's pricing policy and current regulatory framework to improve the efficiency of the market and further enhance competition in natural gas markets.

With respect to the transportation of natural gas on or across the Outer Continental Shelf ("OCS"), the FERC requires, as part of its regulation under the Outer Continental Shelf Lands Act, that all pipelines provide open and non-discriminatory access to both owner and non-owner shippers. Although to date the FERC has imposed light-handed regulation on off-shore facilities that meet its traditional test of gathering status, it has the authority to exercise jurisdiction under the Outer Continental Shelf Lands Act ("OCSLA") over gathering facilities, if necessary, to permit non-discriminatory access to service. For those facilities transporting natural gas across the OCS that are not considered to be gathering facilities, the rates, terms, and conditions applicable to this transportation are regulated by FERC under the NGA and NGPA, as well as the OCSLA.

SALES AND TRANSPORTATION OF CRUDE OIL. Sales of crude oil and condensate can be made by the Company at market prices not subject at this time to price controls. The price that the Company receives from the sale of these products will be affected by the cost of transporting the products to market. The rates, terms, and conditions applicable to the interstate transportation of oil and related products by pipelines are regulated by the FERC under the Interstate Commerce

Act. As required by the Energy Policy Act of 1992, the FERC has revised its regulations governing the rates that may be charged by oil pipelines. The new rules, which were effective January 1, 1995, provide a simplified, generally applicable method of regulating such rates by use of an index for setting rate ceilings. The FERC will also, under defined circumstances, permit alternative ratemaking methodologies for interstate oil pipelines such as the use of cost of service rates, settlement rates, and market-based rates. Market-based rates will be permitted to the extent the pipeline can demonstrate that it lacks significant market power in the market in which it proposes to charge market-based rates. The cumulative effect that these rules may have on moving the Company's production to market cannot yet be determined.

With respect to the transportation of oil and condensate on or across the OCS, the FERC requires, as part of its regulation under the OCSLA, that all pipelines provide open and non-discriminatory access to both owner and non-owner shippers. Accordingly, the FERC has the authority to exercise jurisdiction under the OCSLA, if necessary, to permit non-discriminatory access to service.

LEGISLATIVE PROPOSALS. In the past, Congress has been very active in the area of natural gas regulation. There are legislative proposals pending in Congress and in various state legislatures which, if enacted, could significantly affect the petroleum industry. At the present time it is impossible to predict what proposals, if any, might actually be enacted by Congress or the various state legislatures and what effect, if any, such proposals might have on the Company's operations.

FEDERAL, STATE OR INDIAN LEASES. In the event the Company conducts operations on federal, state or Indian oil and gas leases, such operations must comply with numerous regulatory restrictions, including various nondiscrimination statutes, royalty and related valuation requirements, and certain of such operations must be conducted pursuant to certain on-site security regulations and other appropriate permits issued by the Bureau of Land Management ("BLM") or Minerals Management Service ("MMS") or other appropriate federal or state agencies.

The Company's OCS leases in federal waters are administered by the MMS and require compliance with detailed MMS regulations and orders. The MMS has promulgated regulations implementing restrictions on various production-related activities, including restricting the flaring or venting of natural gas. Under certain circumstances, the MMS may require Company operations on federal leases to be suspended or terminated. Any such suspension or termination could materially and adversely affect the Company's financial condition and operations. On March 15, 2000, the MMS issued a final rule effective June 1, 2000 which amends its regulations governing the calculation of royalties and the valuation of crude oil produced from federal leases. Among other matters, this rule amends the valuation procedure for the sale of federal royalty oil by eliminating posted prices as a measure of value and relying instead on arm's length sales prices and spot market prices as market value indicators. Because the Company sells its production in the spot market and therefore pays royalties on production from federal leases, it is not anticipated that this final rule will have any substantial impact on the Company.

The Mineral Leasing Act of 1920 ("Mineral Act") prohibits direct or indirect ownership of any interest in federal onshore oil and gas leases by a foreign citizen of a country that denies "similar or like privileges" to citizens of the United States. Such restrictions on citizens of a "non-reciprocal" country include ownership or holding or controlling stock in a corporation that holds a federal onshore oil and gas lease. If this restriction is violated, the corporation's lease can be canceled in a proceeding instituted by the United States Attorney General. Although the regulations of the BLM (which administers the Mineral Act) provide for agency designations of non-reciprocal countries, there are presently no such designations in effect. The Company owns interests in numerous federal onshore oil and gas leases. It is possible that holders of equity interests in the Company may be citizens of foreign countries, which at some time in the future might be determined to be non-reciprocal under the Mineral Act.

STATE REGULATIONS

Most states regulate the production and sale of oil and natural gas, including requirements for obtaining drilling permits, the method of developing new fields, the spacing and operation of wells and the prevention of waste of oil and gas resources. The rate of production may be regulated and the maximum daily production allowable from both oil and gas wells may be established on a market demand or conservation basis or both.

The Company may enter into agreements relating to the construction or operation of a pipeline system for the transportation of natural gas. To the extent that such gas is produced, transported and consumed wholly within one state, such operations may, in certain instances, be subject to the jurisdiction of such state's administrative authority charged with the responsibility of regulating intrastate pipelines. In such event, the rates which the Company could charge for gas, the transportation of gas, and the costs of construction and operation of such

pipeline would be impacted by the rules and regulations governing such matters, if any, of such administrative authority. Further, such a pipeline system would be subject to various state and/or federal pipeline safety regulations and requirements, including those of, among others, the Department of Transportation. Such regulations can increase the cost of planning, designing, installing and operating such facilities. The impact of such pipeline safety regulations would not be any more adverse to the Company than it would be to other similar owners or operators of such pipeline facilities.

ENVIRONMENTAL REGULATIONS

GENERAL. The Company's activities are subject to federal, state and local laws and regulations governing environmental quality and pollution control. Although no assurances can be made, the Company believes that, absent the occurrence of an extraordinary event, compliance with existing federal, state and local laws, rules and regulations regulating the release of materials into the environment or otherwise relating to the protection of the environment will not have a material effect upon the capital expenditures, earnings or the competitive position of the Company with respect to its existing assets and operations. The Company cannot predict what effect future regulation or legislation, enforcement policies, and claims for damages to property, employees, other persons and the environment resulting from the Company's operations could have on its activities.

Activities of the Company with respect to natural gas facilities, including the operation and construction of pipelines, plants and other facilities for transporting, processing, treating or storing natural gas and other products, are subject to stringent environmental regulation by state and federal authorities including the United States Environmental Protection Agency ("EPA"). Such regulation can increase the cost of planning, designing, installing and operating such facilities. In most instances, the regulatory requirements relate to water and air pollution control measures. Although the Company believes that compliance with environmental regulations will not have a material adverse effect on it, risks of substantial costs and liabilities are inherent in oil and gas production operations, and there can be no assurance that significant costs and liabilities will not be incurred. Moreover, it is possible that other developments, such as stricter environmental laws and regulations, and claims for damages to property or persons resulting from oil and gas production, would result in substantial costs and liabilities to the Company.

SOLID AND HAZARDOUS WASTE. The Company currently owns or leases, and in the past owned or leased, properties that have been used for the exploration and production of oil and gas for many years. Although the Company has utilized operating and disposal practices that were standard in the industry at the time, hydrocarbons or other solid wastes may have been disposed or released on or under the properties owned or leased by the Company or on or under locations where such wastes have been taken for disposal. In addition, many of these properties have been operated by third parties. The Company has no control over such entities' treatment of hydrocarbons or other solid wastes and the manner in which such substances may have been disposed or released. State and federal laws applicable to oil and gas wastes and properties have gradually become stricter over time. Under new laws, the Company could be required to remediate property, including groundwater, containing or impacted by previously disposed wastes (including wastes disposed or released by prior owners or operators, or property contamination, including groundwater contamination by prior owners or operators) or to perform remedial plugging operations to prevent future or mitigate existing contamination.

The Company generates wastes, including hazardous wastes that are subject to the federal Resource Conservation and Recovery Act ("RCRA") and comparable state statutes. The Environmental Protection Agency ("EPA") and various state agencies have limited the disposal options for certain wastes, including wastes designated as hazardous under the RCRA and similar state statutes ("Hazardous Wastes"). Furthermore, it is possible that certain wastes generated by the Company's oil and gas operations that are (currently exempt from

treatment as) Hazardous Wastes may in the future be designated as Hazardous Wastes under RCRA or other applicable statutes and, therefore, may be subject to more rigorous and costly disposal requirements.

SUPERFUND. The federal Comprehensive Environmental Response, Compensation and Liability Act ("CERCLA"), also known as the "Superfund" law, generally imposes joint and several liability for costs of investigation and remediation and for natural resource damages, without regard to fault or the legality of the original conduct, on certain classes of persons with respect to the release into the environment of substances designated under CERCLA as hazardous substances ("Hazardous Substances"). These classes of persons, or so-called potentially responsible parties ("PRPs"), include the current and certain past owners and operators of a facility where there has been a release or threat of release of a Hazardous Substance and persons who disposed of or arranged for the disposal of Hazardous Substances found at a site. CERCLA also authorizes the EPA and, in some cases, third parties to take actions in response to threats to the public health or the environment and to seek to recover from the PRPs the costs of such action. Although CERCLA generally exempts "petroleum" from the definition of Hazardous Substance, in the course of its operations, the Company has generated and will generate wastes that may fall within CERCLA's definition of Hazardous Substance. The Company may also be the owner or operator of sites on which Hazardous Substances have been released. To its knowledge, neither the Company nor its predecessors have been designated as a PRP by the EPA under CERCLA; the Company also does not know of any prior owners or operators of its properties that are named as PRPs related to their ownership or operation of such properties.

CLEAN WATER ACT. The Clean Water Act ("CWA") imposes restrictions and strict controls regarding the discharge of wastes including produced waters and other oil and natural gas wastes, into waters of the United States, a term broadly defined. These controls have become more stringent over the years, and it is probable that additional restrictions will be imposed in the future. Permits must be obtained to discharge pollutants into federal waters. The CWA provides for civil, criminal and administrative penalties for unauthorized discharges of oil and hazardous substances and of other pollutants. It imposes substantial potential liability for the costs of removal or remediation associated with discharges of oil or hazardous substances and other pollutants. State laws governing discharges to water also provide varying civil, criminal and administrative penalties and impose liabilities in the case of a discharge of petroleum or its derivatives, or other hazardous substances, into state waters. In addition, the EPA has promulgated regulations that may require us to obtain permits to discharge storm water runoff, including discharges associated with construction activities. In the event of an unauthorized discharge of wastes, the Company may be liable for penalties and costs.

OIL POLLUTION ACT. The Oil Pollution Act of 1990 ("OPA"), which amends and augments oil spill provisions of CWA, imposes certain duties and liabilities on certain "responsible parties" related to the prevention of oil spills and damages resulting from such spills in or threatening United States waters or adjoining shorelines. A liable "responsible party" includes the owner or operator of a facility, vessel or pipeline that is a source of an oil discharge or that poses the substantial threat of discharge, or the lessee or permittee of the area in which a discharging facility is located. OPA assigns joint and several liability, without regard to fault, to each liable party for oil removal costs and a variety of public and private damages. Although defenses and limitations exist to the liability imposed by OPA, they are limited. In the event of an oil discharge or substantial threat of discharge, the Company may be liable for costs and damages.

The OPA also imposes ongoing requirements on a responsible party, including proof of financial responsibility to cover at least some costs in a potential spill. Certain amendments to the OPA that were enacted in 1996 require owners and operators of offshore facilities that have a worst case oil spill potential of more than 1,000 barrels to demonstrate financial responsibility in amounts ranging from $10 million in specified state waters and $35 million in federal outer continental shelf ("OCS") waters, with higher amounts, up to $150 million based upon worst

case oil-spill discharge volume calculations. The Company believes that it has established adequate proof of financial responsibility for its offshore facilities.

AIR EMISSIONS. The Company's operations are subject to local, state and federal regulations for the control of emissions from sources of air pollution. Federal and state laws require new and modified sources of air pollutants to obtain permits prior to commencing construction. Major sources of air pollutants are subject to more stringent, federally imposed requirements including additional permits. Federal and state laws designed to control hazardous (toxic) air pollutants, might require installation of additional controls. Administrative enforcement actions for failure to comply strictly with air pollution regulations or permits are generally resolved by payment of monetary fines and correction of any identified deficiencies. Alternatively, regulatory agencies could bring lawsuits for civil penalties or require the Company to forego construction, modification or operation of certain air emission sources.

COASTAL COORDINATION. There are various federal and state programs that regulate the conservation and development of coastal resources. The federal Coastal Zone Management Act ("CZMA") was passed in 1972 to preserve and, where possible, restore the natural resources of the Nation's coastal zone. The CZMA provides for federal grants for state management PROGRAMS that regulate land use, water use and coastal development.

Various states, such as Alabama, Louisiana and Texas, also have coastal management programs, which provide for, among other things, the coordination among local and state authorities to protect coastal resources through regulating land use, water, and coastal development. Coastal management programs also may provide for the review of state and federal agency rules and agency actions for consistency with the goals and policies of the state coastal management plan. This review may impact agency permitting and review activities and add an additional layer of review to certain activities undertaken by the Company.

OSHA AND OTHER REGULATIONS. The Company is subject to the requirements of the federal Occupational Safety and Health Act ("OSHA") and comparable state statutes. The OSHA hazard communication standard, the EPA community right-to-know regulations under Title III of CERCLA and similar state statutes require the Company to organize and/or disclose information about hazardous materials used or produced in its operations.

Management believes that the Company is in substantial compliance with current applicable environmental laws and regulations and that continued compliance with existing requirements would not have a material adverse impact on the Company.

PROPERTY SUMMARY

We are engaged in the exploration, development, acquisition and production of oil and gas properties and natural gas transmission and provide oil and gas property management services for other investors. Our properties are concentrated offshore in the Gulf of Mexico and onshore, primarily, in Louisiana and Alabama. We have historically grown our reserves and production by focusing primarily on low to moderate risk exploration and acquisition opportunities in the Gulf of Mexico Shelf area. Over the last several years, we have expanded our area of exploration to include the Gulf of Mexico Deepwater area. As of December 31, 2002, our estimated net proved reserves totaled 24.0 million barrels of oil

("MBbl") and 91.5 billion cubic feet of natural gas ("Bcf"), with a pre-tax present value, discounted at 10%, of the estimated future net revenues based on constant prices in effect at year-end ("Discounted Cash Flow") of $623.9 million. Gas constitutes approximately 39% of our total estimated proved reserves and approximately 17% of our total estimated proved reserves are proved producing reserves.

Our Medusa (Mississippi Canyon Blocks 538/582) discovery and Habanero (Garden Banks Block 341) discovery are projected to begin production late in the third quarter of 2003. Construction of a production facility, subsea completions and flowlines are projected to be completed by the fall of 2003. These two deepwater discoveries are expected to increase our projected production from our existing producing properties by 58% in the second half of 2003. A detail discussion of each of these properties is provided in the Significant Properties section of this report.

SIGNIFICANT PROPERTIES

The following table shows discounted cash flows and estimated net proved oil and gas reserves by major field, within the focus area, for our seven largest fields and for all other properties combined at December 31, 2002.

<Table>
<Caption>

<S>	OPERATOR <C>	ESTIMATED NET PROVED RESERVES: OIL (MBbls) <C>	GAS (MMcf) <C>	TOTAL (MMcfe) <C>	PRE-TAX DISCOUNTED RESENT VALUE ($000) (a) <C>
GULF OF MEXICO DEEPWATER:					
Mississippi Canyon Blocks 538/582 "Medusa"	Murphy	10,479	8,460	71,336	$ 226,810
Garden Banks Block 341 "Habanero"	Shell	4,736	11,280	39,696	103,589
Garden Banks Blocks 738/782/826/827 "Entrada"	BP Amoco	7,772	29,126	75,761	164,272

</Table>

<Table>

<S>	<C>	<C>	<C>	<C>	<C>
GULF OF MEXICO SHELF:					
Mobile Blocks 863/864/907/908	Callon	--	9,991	9,991	27,866
Mobile Blocks 952/953/955	Callon	--	23,117	23,117	76,382
Ship Shoal Blocks 28/35	Callon	12	1,141	1,210	3,722
ONSHORE AND OTHER:					
Big Escambia Creek	Exxon	353	1,298	3,414	8,199
Other	Various	691	7,126	11,274	13,106
TOTAL NET PROVED RESERVES		24,043	91,539	235,799	$ 623,946

</Table>

(a) Represents the present value of future net cash flows before deduction of federal income taxes, discounted at 10%, attributable to estimated net proved reserves as of December 31, 2002, as set forth in the Company's reserve reports prepared by its independent petroleum reserve engineers, Huddleston & Co., Inc. of Houston, Texas.

GULF OF MEXICO DEEPWATER

Medusa, Mississippi Canyon Blocks 538/582

Medusa was our third deepwater discovery and was announced in September 1999. We drilled the initial test well in 2,235 feet of water to a total depth of 16,241 feet and encountered over 120 feet of pay in two intervals. We performed subsequent sidetrack drilling from the well bore to determine the extent of the discovery. We drilled a second successful well in the first quarter of 2000 to further delineate the extent of the pay intervals. We own a 15% working interest, Murphy, the operator, owns a 60% interest and Agip Ventures, formerly British-Borneo Petroleum, Inc., owns the remaining 25% interest.

In 2001 a drilling program began which included four development wells and one sidetrack. The program included production casing being set on six wells which will provide initial production take-points. The program was completed in the first half of 2002. Also in 2001, the operator submitted an Authorization

for Expenditure for a floating production system at Medusa and awarded the contract to J. Ray McDermott, Inc. The spar was barged to the Mississippi Canyon Block 582 in January 2003 and installed. The topside deck and production facilities should be delivered and lifted into place atop the spar during the second quarter of 2003. Initial production is scheduled to commence in the third quarter of 2003 as the six wells are individually completed and tied into the spar and production facilities. Once all six wells are tied in, it is estimated that the production facility will have the capacity to handle up to 40,000 barrels of crude oil and 110 million cubic feet of natural gas per day.

Habanero, Garden Banks Block 341

During February 1999 the initial test well on our Habanero prospect encountered over 200 feet of net pay in two zones. Located in 2,000 feet of water, the well was drilled to a measured depth of 21,158 feet. This discovery was our second deepwater success. We own an 11.25% working interest in the well. It is operated by Shell Deepwater Development Inc., which owns a 55% working interest, with the remaining working interest being owned by Murphy.

Current development plans include sub-sea completion and tie back to an existing production facility in the area that is operated by Shell. A field delineation program began in mid-year 2001, which included sidetracking the discovery well with three sidetracks. Production casing was set on this well through one of the sidetracks to the Hab 52 oil sand and the Hab 55 gas sand. Initial production will be from the Hab55 gas sand and future recompletions are scheduled up-hole to the Hab 52 oil sand for this well. Also, a development well is scheduled to be drilled in the summer of 2003 and will provide a take-point for production from the Hab 52 oil sand. The operator has submitted to the co-owners a development schedule which estimates initial production to commence in late summer 2003.

Entrada, Garden Banks Blocks 738/782/826/827

The Entrada discovery is located in approximately 4,500 feet of water in the Gulf of Mexico. Two wells and seven sidetracks have been drilled to date on Garden Banks 782 on a northwest plunging salt ridge along the southern edge of the Entrada Basin. Multiple stacked amplitudes trapped against a salt or fault interface characterize the Entrada Area. We own a 20% working interest in this discovery with BP Amoco, the operator, holding the remaining working interest.

The owners of an adjacent discovery have announced their plans to construct production facilities to enable them to be a regional off-take point in Southeastern Garden Banks. These plans include handling third party tie-ins, which we expect to include Entrada. First production from their discovery is expected in late 2004. Information obtained in a data swap with the adjacent owners, is being incorporated into the Entrada development plans. An integrated project team was formed by the working interest owners during 2002 to begin planning the development of the field.

Boomslang, Ewing Bank Block 994

A major revision to reserves in 2002 was at our Boomslang discovery. The initial exploratory well drilled at this location in 1998 encountered 185 feet of pay. The first well was drilled with significant mechanical problems and was subsequently determined not to be a viable well for completion and production of the estimated proved reserves encountered in this initial well. A second well, to serve as a production take point, was drilled in the fourth quarter of 2002 in a down dip direction from the first well targeting what was anticipated to be a better sand development in the three separate reservoirs found in the first well, but still up dip of the lowest known hydrocarbons in the first well. Reservoir sand quality changed dramatically, reducing the estimated reservoir volumes found and booked as estimated proved reserves by the first well

to an extent that the partners determined that the risk of development was not economic. Callon had a 40% working interest. The Company's proved reserves in the prior year included 7.2 million barrels of oil and 13 billion cubic feet of natural gas attributable to Boomslang.

GULF OF MEXICO SHELF

Mobile Blocks 863/864/ 907/908

We own an average 67.9% working interest in these blocks and we are the operator. The Mobile 864 unit, in which we have a 66.4% working interest, has three producing wells, unit production facilities and covers portions of these four blocks. In addition, there are two other wells located on the blocks in which we own a 100% and 66.4% working interest. These wells produce through the unit facilities. During 2002 the unit and the other two wells produced an average of 7.1 MMcf per day net to us.

Mobile Blocks 952/953/955

We own a 100% working interest in these three blocks and we are the operator. In the fourth quarter of 2001, we initiated a production acceleration program for Mobile Blocks 952, 953 and 955, which were being produced through the Mobile Block 864 unit facilities. Plans included an acceleration well, which was successfully drilled in the fourth quarter of 2001. Stand-alone production facilities were installed and production flow lines were rerouted to the new facilities. Production commenced through the new facilities in April 2002. This program offset normal production declines curves from existing field wells and added an annual increase of 3.8 MMcf per day net to us over 2001 production levels of 10.1 MMcf per day. From May 1, 2002 to December 31, 2002 the wells produced 18.6 MMcf per day net to us.

Ship Shoal Blocks 28/35

We successfully drilled an exploratory well on our prospect at Ship Shoal Blocks 28 and 35 during the third quarter of 2002. The well was drilled to a measured depth of 15,237 feet (12,295 feet of true vertical depth) and encountered 140 feet of net natural gas pay. The well is being completed as a single producer in the deepest of three productive intervals and is scheduled for first production during the second quarter of 2003. We operate and own a 22% working interest.

ONSHORE AND OTHER

Big Escambia Creek

This gas field in south Alabama produces from the Smackover formation at depths ranging from 15,100 to 15,600 and is operated by Exxon/Mobil. We own an average working interest of 4.9% (5.5% net revenue interest), in six wells and a 2.2% average royalty interest in another five wells. This field produced 1.0 MMcfe per day to our interest in 2002. The field has an estimated reserve life in excess of ten years given current production rates.

Other

We own various royalty and working interest in numerous onshore areas and the Gulf of Mexico other than the fields discussed above.

OIL AND GAS RESERVES

The following table sets forth certain information about our estimated proved reserves as of the dates set forth below.

	YEARS ENDED DECEMBER 31,		
	2002	2001(a)	2000(a)
	(IN THOUSANDS)		
Proved developed:			
Oil (Bbls)	1,056	885	2,192
Gas (Mcf)	37,631	52,375	67,463
Proved undeveloped:			
Oil (Bbls)	22,988	29,324	31,190
Gas (Mcf)	53,908	69,078	65,940
Total proved:			
Oil (Bbls)	24,043	30,209	33,382
Gas (Mcf)	91,539	121,453	133,403
Estimated pre-tax future net cash flows	$ 970,198	$ 473,896	$ 1,610,320
Pre-tax discounted present value	$ 623,946	$ 272,053	$ 939,325
Standardized measure of discounted future net cash flows	$ 556,046	$ 254,857	$ 671,197

(a) The estimates include reserve volumes of approximately 3.5 Bcf, $31.8 million of pre-tax future net cash flows and $29.5 million of pre-tax discounted present value in 2000, 1.2 Bcf, $2.9 million of pre-tax discounted present value in 2001, attributable to a volumetric production payment. Standardized measure of discounted future net cash flows does not include any volumes or cash flows associated with the volumetric production payment.

Our independent reserve engineers, Huddleston & Co., Inc. prepared the estimates of the proved reserves and the future net cash flows and present value thereof attributable to such proved reserves. Reserves were estimated using oil and gas prices and production and development costs in effect on December 31 of each such year, without escalation, and were otherwise prepared in accordance with Securities and Exchange Commission regulations regarding disclosure of oil and gas reserve information.

There are numerous uncertainties inherent in estimating quantities of proved reserves, including many factors beyond our control or the control of the reserve engineers. Reserve engineering is a subjective process of estimating underground accumulations of oil and gas that cannot be measured in an exact manner. The accuracy of any reserve or cash flow estimate is a function of the quality of available data and of engineering and geological interpretation and judgment. Estimates by different engineers often vary, sometimes significantly. In addition, physical factors, such as the results of drilling, testing and production subsequent to the date of an

estimate, as well as economic factors, such as an increase or decrease in product prices that renders production of such reserves more or less economic, may justify revision of such estimates. Accordingly, reserve estimates could be different from the quantities of oil and gas that are ultimately recovered.

We have not filed any reports with other federal agencies which contain an estimate of total proved net oil and gas reserves during our last fiscal year.

PRESENT ACTIVITIES AND PRODUCTIVE WELLS

The following table sets forth the wells we have drilled and completed during the periods indicated. All such wells were drilled in the continental United States primarily in federal and state waters in the Gulf of Mexico.

<Table>
<Caption>

	YEARS ENDED DECEMBER 31,					
	2002		2001		2000	
	GROSS	NET	GROSS	NET	GROSS	NET
<S>	<C>	<C>	<C>	<C>	<C>	<C>
Development:						
Oil	2	.30	6	.45	2	.35
Gas	--	--	4	3.17	--	--
Non-productive	1	.40	--	--	--	--
Total	3	.70	10	3.62	2	.35
Exploration:						
Oil	--	--	--	--	1	.20
Gas	1	.22	3	2.00	2	2.00
Non-productive	1	.50	12	5.77	6	2.29
Total	2	.72	15	7.77	9	4.49

</Table>

The following table sets forth our productive wells as of December 31, 2002:

<Table>
<Caption>

	WELLS	
	GROSS	NET
Oil:		
<S>	<C>	<C>
Working interest	39.00	3.07
Royalty interest	220.00	3.40
Total	259.00	6.47
Gas:		
Working interest	45.00	21.25
Royalty interest	243.00	1.51
Total	288.00	22.76

</Table>

A well is categorized as an oil well or a natural gas well based upon the ratio of oil to gas reserves on a Mcfe basis. However, some of our wells produce both oil and gas. At December 31, 2002, we had no wells with multiple completions. At December 31, 2002, we had 1 gross (1.0 net) exploratory gas well in progress.

LEASEHOLD ACREAGE

The following table shows our approximate developed and undeveloped (gross and net) leasehold acreage as of December 31, 2002.

<Table>
<Caption>

	LEASEHOLD ACREAGE			
	DEVELOPED		UNDEVELOPED	
LOCATION	GROSS	NET	GROSS	NET
Louisiana	7,862	4,835	3,801	1,237
Other States	1,500	740	879	689
Federal Waters	116,566	82,442	300,475	98,231
Total	125,928	88,017	305,155	100,157

</Table>

As of December 31, 2002, we owned various royalty and overriding royalty interests in 1,336 net developed and 6,862 net undeveloped acres. In addition, we owned 5,181 developed and 120,819 undeveloped mineral acres.

MAJOR CUSTOMERS

Our production is sold generally on month-to-month contracts at prevailing prices. The following table identifies customers to whom we sold a significant percentage of our total oil and gas production during each of the twelve-month periods ended:

<Table>
<Caption>

	DECEMBER 31,		
	2002	2001	2000
Adams Resources Marketing, Ltd.	--	--	14%
Petrocom Energy Group, Ltd.	4%	--	--
Dynegy	7%	8%	--
Prior Energy Corporation	--	20%	--
Reliant Energy Services	70%	49%	37%
Unocal Exploration Corporation	--	--	8%

</Table>

Because alternative purchasers of oil and gas are readily available, we believe that the loss of any of these purchasers would not result in a material adverse effect on our ability to market future oil and gas production.

TITLE TO PROPERTIES

We believe that the title to our oil and gas properties is good and defensible in accordance with standards generally accepted in the oil and gas industry, subject to such exceptions which, in our opinion are not so material as to detract substantially from the use or value of such properties. Our properties are typically subject, in one degree or another, to one or more of the following: royalties and other burdens and obligations, express or implied, under oil and gas leases; overriding royalties and other burdens created by us or our predecessors in title; a variety of contractual obligations (including, in some cases, development obligations) arising under operating agreements, farmout agreements, production sales contracts and other agreements that may affect the properties or their titles; back-ins and reversionary interests existing under purchase agreements and leasehold assignments; liens that arise in the normal course of operations, such as those for unpaid taxes, statutory liens securing obligations to unpaid suppliers and contractors and contractual liens under operating agreements; pooling, unitization and communitization agreements, declarations and orders; and easements, restrictions, rights-of-way and other matters that commonly affect property. To the extent that such burdens and obligations affect our rights to production revenues, they have been taken into account in calculating our net revenue interests and in estimating the size and value of our reserves. We believe that the burdens and obligations affecting our properties are conventional in the industry for properties of the kind owned by us.

ITEM 3. LEGAL PROCEEDINGS

We are a defendant in various legal proceedings and claims, which arise in the ordinary course of our business. We do not believe the ultimate resolution of any such actions will have a material affect on our financial position or results of operations.

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

There were no matters submitted to a vote of security holders during the fourth quarter of 2002.

PART II.

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

Our common stock trades on the New York Stock Exchange under the symbol "CPE". The following table sets forth the high and low sale prices per share as reported for the periods indicated.

<Table>
<Caption>

QUARTER ENDED	HIGH	LOW
2001:		
First quarter	$ 16.69	$ 10.00
Second quarter	13.22	10.65
Third quarter	11.82	5.90
Fourth quarter	7.20	5.35
2002:		
First quarter	$ 9.40	$ 3.97
Second quarter	8.39	4.50
Third quarter	5.15	3.20
Fourth quarter	6.25	3.35

</Table>

As of March 7, 2003, there were approximately 4,896 common stockholders of record.

We have never paid dividends on our common stock and intend to retain our cash flow from operations, net of preferred stock dividends, for the future operation and development of our business. In addition, our primary credit facility and the terms of our outstanding subordinated debt restrict payments of dividends on our common stock.

ITEM 6. SELECTED FINANCIAL DATA

The following table sets forth, as of the dates and for the periods indicated, selected financial information about us. The financial information for each of the five years in the period ended December 31, 2002 has been derived from our audited Consolidated Financial Statements for such periods. The information should be read in conjunction with "Management's Discussion and Analysis of Financial Condition and Results of Operations" and the Consolidated Financial Statements and Notes thereto. The following information is not necessarily indicative of our future results.

CALLON PETROLEUM COMPANY
SELECTED HISTORICAL FINANCIAL INFORMATION
(IN THOUSANDS, EXCEPT PER SHARE AMOUNTS)

<Table>
<Caption>

	YEARS ENDED DECEMBER 31,				
	2002	2001	2000	1999	1998
<S>	<C>	<C>	<C>	<C>	<C>
STATEMENT OF OPERATIONS DATA:					
Revenues:					
Oil and gas sales	$ 61,171	$ 60,010	$ 56,310	$ 37,140	$ 35,624
Interest and other	1,004	1,742	1,767	1,853	2,094
Gain on sale of pipeline	2,454	--	--	--	--
Gain on sale of Enron derivatives	2,479	--	--	--	--
Total revenues	67,108	61,752	58,077	38,993	37,718
Costs and expenses:					
Lease operating expenses	11,030	11,252	9,339	7,536	7,817
Depreciation, depletion and amortization	27,096	21,081	17,153	16,727	19,284
General and administrative	4,705	4,635	4,155	4,575	5,285
Writedown of Enron derivatives	--	9,186	--	--	--
Loss on mark-to-market commodity derivative contracts	708	--	--	--	--
Interest	26,140	12,805	8,420	6,175	1,925
Accelerated vesting and retirement benefits	--	--	--	--	5,761
Impairment of oil and gas properties	--	--	--	--	43,500
Total costs and expenses	69,679	58,959	39,067	35,013	83,572
Income (loss) from operations	(2,571)	2,793	19,010	3,980	(45,854)
Income tax expense (benefit)	(900)	977	6,463	1,353	(15,100)
Net income (loss)	(1,671)	1,816	12,547	2,627	(30,754)
Preferred stock dividends	1,277	1,277	2,403	2,497	2,779
Net income (loss) available to common shares	$ (2,948)	$ 539	$ 10,144	$ 130	$ (33,533)
Net income (loss) per common share:					
Basic	$ (.22)	$ .04	$ .82	$ .01	$ (4.17)
Diluted	$ (.22)	$ .04	$ .80	$ .01	$ (4.17)
Shares used in computing net income (loss) per common share:					
Basic	13,387	13,273	12,420	8,976	8,034
Diluted	13,387	13,366	12,745	9,075	8,034
BALANCE SHEET DATA (END OF PERIOD):					
Oil and gas properties, net	$ 377,661	$ 343,158	$ 258,613	$ 194,365	$ 141,905
Total assets	$ 410,613	$ 372,095	$ 301,569	$ 259,877	$ 181,652
Long-term debt, less current portion	$ 248,269	$ 161,733	$ 134,000	$ 100,250	$ 78,250
Stockholders' equity	$ 140,960	$ 147,224	$ 136,328	$ 124,380	$ 84,484

</Table>

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We use the full-cost method of accounting. Under this method of accounting, our net capitalized costs to acquire, explore and develop oil and gas properties may not exceed the standardized measure of our proved reserves. If these capitalized costs exceed a ceiling amount, the excess is charged to expense. As a result of the significant decline in oil and gas prices, we recorded a non-cash impairment expense related to our oil and gas properties in the amount of $43.5 million during the fourth quarter of 1998.

ITEM 7. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

The following discussion is intended to assist in an understanding of our financial condition and results of operations. Our Financial Statements and Notes thereto contain detailed information that should be referred to in conjunction with the following discussion. See Item 8. "Financial Statements and

Supplementary Data."

GENERAL

Callon Petroleum Company has been engaged in the exploration, development, acquisition and production of oil and gas properties since 1950. Our revenues, profitability and future growth and the carrying value of our oil and gas properties are substantially dependent on prevailing prices of oil and gas and our ability to find, develop and acquire additional oil and gas reserves that are economically recoverable. Our ability to maintain or increase our borrowing capacity and to obtain additional capital on attractive terms is also influenced by oil and gas prices.

Our estimated net proved oil and gas reserves decreased at December 31, 2002 to 236 billion cubic feet of natural gas equivalent (Bcfe). This represents a decrease of 22% over previous year-end 2001 estimated proved reserves of 303 Bcfe.

A major revision to reserves in 2002 was at our Boomslang discovery. The initial exploratory well drilled at this location in 1998 encountered 185 feet of pay. The well was drilled with mechanical problems and was subsequently determined not to be a viable well for completion and production of the estimated proved reserves encountered in this initial well. A second well, drilled in the fourth quarter of 2002, to serve as a production take point, was drilled in a down dip direction from the first well targeting what was anticipated to be a better sand development in the three separate reservoirs found in the first well, but still up dip of the lowest known hydrocarbons in the first well. Reservoir sand quality changed dramatically, reducing the estimated reservoir volumes found and booked as estimated proved reserves by the first well to an extent that the partners determined that the risk of development was not economic. Callon had a 40% working interest. The Company's proved reserves in the prior year included 7.2 million barrels of oil and 13 billion cubic feet of natural gas attributable to Boomslang.

Prices for oil and gas are subject to large fluctuations in response to relatively minor changes in the supply of and demand for oil and gas, market uncertainty and a variety of additional factors beyond our control. These factors include weather conditions in the United States, the condition of the United States economy, the actions of the Organization of Petroleum Exporting Countries, governmental regulation, political stability in the Middle East and elsewhere, the foreign supply of crude oil and natural gas, the price of foreign imports and the availability of alternate fuel sources. Any substantial and extended decline in the price of crude oil or natural gas would have an adverse effect on our carrying value of our proved reserves, borrowing capacity, revenues, profitability and cash flows from operations. We use derivative financial instruments (see Note 6 and Item 7A. "Quantitative and Qualitative Disclosures About Market Risks") for price protection purposes on a limited amount of our future production and do not use them for trading purposes. On a Mcfe basis, natural gas represents 65% of the budgeted 2003 production and 39% of proved reserves at year-end 2002.

Inflation has not had a material impact on us and is not expected to have a material impact on us in the future.

SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

RECENT ACCOUNTING PRONOUNCEMENTS. In June 1998, the Financial Accounting Standards Board issued Statement of Financial Accounting Standards No. 133 ("SFAS 133"), Accounting for Derivative Instruments and Hedging Activities. The Statement establishes accounting and reporting standards requiring that every derivative instrument, including certain derivative instruments embedded in other contracts, be recorded in the balance sheet as either an asset or liability measured at its fair value. SFAS 133 requires the Company to report changes in the fair value of our derivative financial instruments that qualify as cash flow hedges in other comprehensive income, a component of stockholders' equity, until realized. We adopted SFAS 133 effective January 1, 2001.

In June 2001, the Financial Accounting Standards Board approved Statement of Accounting Standards No. 143, Asset Retirement Obligations ("SFAS 143"). SFAS 143 addresses financial accounting and reporting for obligations associated with the retirement of tangible long-lived assets and the associated asset retirement costs. We will record the fair value of these obligations on January 1, 2003, as well as the related additional assets. The net difference between our previously recorded abandonment liability and the amounts estimated under SFAS 143, after taxes, is expected to total a gain of approximately $180,000, which will

be recognized as a cumulative effect of a change in accounting principle and an expected abandonment liability for retirement obligations of approximately $26 million.

In December 2002, the Financial Accounting Standards Board issued Statement of Financial Accounting Standards No. 148 ("SFAS 148"), "Accounting for Stock-Based Compensation-Transition and Disclosure -an amendment of SFAS No. 123." SFAS 148 amends SFAS 123 to provide alternative methods of transition for a voluntary change to the fair value based method of accounting for stock-based employee compensation. In addition, this statement amends the disclosure requirements of SFAS 123 to require disclosures in both annual and interim financial statements about the method of accounting for stock-based employee compensation and the effect of the method used on the reported results. SFAS 148 is effective for the year ended December 31, 2002 and for interim financial statements commencing in 2003. The adoption of this pronouncement by the Company did not have an impact on our financial condition or results of operations.

PROPERTY AND EQUIPMENT. We follow the full-cost method of accounting for oil and gas properties whereby all costs incurred in connection with the acquisition, exploration and development of oil and gas reserves, including certain overhead costs, are capitalized into the "full cost pool." The amounts we capitalize into the full cost pool are depleted (charged against earnings) using the unit-of-production method. The full cost method of accounting for our proved oil and gas properties requires that we make estimates based on assumptions as to future events which could change. These estimates are described below.

Depreciation, Depletion and Amortization (DD&A) of Oil and Gas Properties. We calculate depletion by using the capitalized costs in our full cost pool plus future development and abandonment costs (combined, the depletable base) and our estimated net proved reserve quantities. Capitalized costs added to the full cost pool and other costs added to the depletable base include the following:

o The cost of drilling and equipping productive wells, dry hole costs, acquisition costs of properties with proved reserves, delay rentals and other costs related to exploration and development of our oil and gas properties;

o Our payroll and general and administrative costs and costs related fringe benefits paid to employees directly engaged in the acquisition, exploration and/or development of oil and gas properties as well as other directly identifiable general and administrative costs associated with such activities. Such capitalized costs do not include any costs related to our production of oil and gas or our general corporate overhead;

o Costs associated with properties that do not have proved reserves attributed to them are excluded from the full cost pool. These unevaluated property costs are added to the full cost pool at such time as wells are completed on the properties, the properties are sold or we determine these costs have been impaired. Our determination that a property has or has not been impaired (which is discussed below) requires that we make assumptions about future events.

o Our estimates of future costs to develop proved properties are added to the full cost pool for purposes of the DD&A computation. We use assumptions based on the latest geologic, engineering, regulatory and cost data available to us to estimate these amounts. However, the estimates we make are subjective and may change over time. Our estimates of future development costs are periodically updated as additional information becomes available.

- Estimated costs to dismantle, abandon and restore a proved property are added to the full cost pool for the purposes of DD&A. Such cost estimates are periodically updated as additional information becomes available. As discussed above under Accounting Pronouncements, specifically FAS 143, beginning January 1, 2003, we will change the method for which we account for such costs

Capitalized costs included in the full cost pool are depleted and charged against earnings using the unit of production method. Under this method, we estimate our quantity of proved reserves at the beginning of each accounting period. For each barrel of oil equivalent produced during the period, we record a depletion charge equal to the amount included in the depletable base (net of accumulated depreciation, depletion and amortization) divided by our estimated net proved reserve quantities.

Because we use estimates and assumptions to calculate proved reserves (as discussed below) and the amounts included in the full cost pool, our depletion calculations will change as the estimates and assumptions are not realized. Such changes may be material.

Ceiling Test. Under the full cost accounting rules, capitalized costs included in the full cost pool, net of accumulated depreciation, depletion and amortization (DD&A) and deferred income taxes, may not exceed the present value of our estimated future net cash flows from proved oil and gas reserves, discounted at 10 percent, plus the lower of cost or fair value of unproved properties included in the costs being amortized, net of related tax effects. These rules generally require that, in estimating future net cash flow, we assume that future oil and gas production will be sold at the unescalated market price for oil and gas received at the end of each fiscal quarter and that future costs to produce oil and gas will remain constant at the prices in effect at the end of the fiscal quarter. We are required to write-down and charge to earnings the amount, if any, by which these costs exceed the discounted future net cash flows, unless prices recover sufficiently before the date of our financial statements. Given the volatility of oil and gas prices, it is likely that our estimates of discounted future net cash flows from proved oil and gas reserves will change in the near term. If oil and gas prices decline significantly, even if only for a short period of time, it is possible that writedowns of oil and gas properties could occur in the future.

Estimating Reserves and Present Values. Our estimates of quantities of proved oil and gas reserves and the discounted present value of such reserves at the end of each quarter are based on numerous assumptions which are likely to change over time. These assumptions include:

- The prices at which we can sell our oil and gas production in the future. Oil and gas process are volatile, but we are generally required to assume that they will not change from the prices in effect at the end of the quarter. In general, higher oil and gas prices will increase quantities of proved reserves and the present value of such reserves, while lower prices will decrease these amounts. Because our properties have relatively short productive lives, changes in prices will affect the present value more than quantities of oil and gas reserves.

- The costs to develop and produce our reserves and the costs to dismantle our production facilities when reserves are depleted. These costs are likely to change over time, but we are required to assume that costs in effect at the end of the quarter will not change. Increases in costs will reduce oil and gas quantities and present values, while decreases in costs will increase such amounts. Because our properties have relatively short productive lives, changes in costs will affect the present value more than quantities of oil and gas reserves.

In addition, the process of estimating proved oil and gas reserves requires that our independent and internal reserve engineers exercise judgment based on available geological, geophysical and technical information. We have described the risks associated with reserve estimation and the volatility of oil and gas prices, under "Risk Factors."

Unproved Properties. Costs associated with properties that do not have proved reserves, including capitalized interest, are excluded from the full cost pool. These unproved properties are included in the line item "Unevaluated properties excluded from amortization." Unproved property costs are transferred to the full cost pool when wells are completed on the properties or the properties are sold. In addition, we are required to

determine whether our unproved properties are impaired and, if so, add the costs of such properties to the full cost pool. We determine whether an unproved property should be impaired by periodically reviewing our exploration program on a property by property basis. This determination may require the exercise of substantial judgment by our management.

DERIVATIVES. We use derivative financial instruments for price protection purposes on a limited amount of our future production and do not use them for trading purposes. Such derivatives were accounted for in years prior to 2001 as hedges and have been recognized as an adjustment to oil and gas sales in the period in which they are related. Current accounting treatment is under SFAS 133.

LIQUIDITY AND CAPITAL RESOURCES

Our primary sources of capital are cash flows from operations, borrowings from financial institutions and the sale of debt and equity securities. Net cash and cash equivalents decreased during 2002 by $1.1 million. Cash provided from operating activities during 2002 totaled $12.2 million. Dividends paid on preferred stock were $1.3 million. Average debt outstanding was $246.0 million during 2002 compared to $164.9 million in 2001. At December 31, 2002, we had working capital of $.6 million.

In early July of 2001, we closed a $95 million multiple advance term loan ("Senior Notes") with a private lender. We drew $45 million on July 3, 2001 and paid down our revolving Credit Facility. We drew the remaining $50 million in December 2001. Under the terms of the agreement, we also issued warrants for the purchase, at a nominal exercise price, of 265,210 shares of our common stock to the lender and conveyed an overriding royalty interest equal to 2% of our net interest in four of our deepwater discoveries. The warrants and the overriding royalty interest were earned by the lender based on the ratio of the amount of the loan proceeds advanced to the total loan facility amount. This senior debt will mature March 31, 2005 and contains restrictions on certain types of future indebtedness and dividends on common stock.

Effective October 31, 2000, we entered into a $75 million Credit Facility with First Union National Bank. Borrowings under the Credit Facility are secured by mortgages covering substantially all of our producing oil and gas properties and guaranteed by our subsidiaries. On June 30, 2002, the lenders under the Company's Credit Facility agreed to increase availability under the revolving borrowing base from $50 million to $75 million.

The Credit Facility, the Senior Notes and our subordinated debt contain various covenants including restrictions on additional indebtedness and payment of cash dividends as well as maintenance of certain financial ratios. We are in compliance with these covenants at December 31, 2002.

The holders of $22.9 million of the $36.0 million of the Company's 10.125% Senior Subordinated Notes (the "Notes") consented to an extension of such Notes until July 31, 2004. The Company granted 274,980 warrants with a fair market value of approximately $1.3 million to purchase Common Stock of the Company and paid consent fees in the amount of $2.3 million to the holders of the Notes that granted the extensions. The holders of the Notes that did not consent to the extension were paid on the maturity date of the Notes in September 2002. Subsequent to September 2002, the holders of the Notes exercised approximately 116,000 warrants that were granted as a result of the extension of the Notes.

Our plans for 2003 include non-discretionary capital expenditures of $51.2 million. Approximately $8.6 million of this amount is allocated to the completion of the Medusa deepwater discovery, currently scheduled to begin production in the third quarter of 2003.

Following Medusa, the Habanero deepwater discovery is scheduled for development with projected capital expenditures in 2003 of approximately $17.2 million and is projected to begin initial production in the second half of 2003. Once producing, this deepwater discovery is projected to have the same positive impact on borrowing capacity as Medusa. Habanero will be produced through a sidetrack of the initial discovery well and the additional development well to be drilled in the summer of 2003. A sub sea completion will be routed into one of the operator's existing facilities and initial production is expected in late third quarter of 2003.

The Company anticipates that cash flow generated during 2003 and current availability under the Credit Facility will provide necessary capital to enable the Company to continue its operational activities until such time as production from Medusa and Habanero begins. At that time, the Company anticipates that the Medusa and Habanero reserves and production will be integrated into the borrowing base of the Company's Credit Facility and will provide additional available borrowing capacity. This increase in borrowing capacity as well as significant additional cash flow from the new production will provide funds for future discretionary capital expenditures.

The completion of the Company's deepwater discoveries will require the construction of expensive production facilities and pipelines, including the transportation and installation of production facilities and the use of sub sea completion techniques. The Company cannot estimate the timing of the construction of these facilities with certainty. The operators completing these discoveries will possibly face inclement weather and other unfavorable environmental conditions, delays in fabrication and delivery of necessary equipment, and other unforeseen circumstances that may delay completion of these properties. Long-term delays in the completion of these deepwater projects that prevent the commencement of production from such discoveries could have a material adverse effect on the Company's financial position and result of operations. Such a delay would require the Company to reduce future anticipated capital expenditures or seek additional sources of liquidity to finance capital expenditures, which may not be available.

The following table describes our outstanding contractual obligations (in thousands) as of December 31, 2002:

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CONTRACTUAL OBLIGATIONS	TOTAL	LESS THAN ONE YEAR	ONE-THREE YEARS	FOUR-FIVE YEARS	AFTER-FIVE YEARS
<S>	<C>	<C>	<C>	<C>	<C>
Credit Facility	$ 65,000	$ --	$ 65,000	$ --	$ --
Senior Notes	95,000	--	95,000	--	--
10.125% Senior Subordinated Debt	22,915	--	22,915	--	--
10.25% Senior Subordinated Debt	40,000	--	40,000	--	--
11% Senior Subordinated Debt	33,000	--	33,000	--	--
Capital lease (future minimum payments)	6,419	1,998	2,712	787	923

</Table>

RESULTS OF OPERATIONS

The following table sets forth certain operating information with respect to our oil and gas operations for each of the three years in the period ended December 31, 2002.

<Table>
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	DECEMBER 31,		
	2002(a)(b)	2001(a)(b)	2000(a)(b)

	------------	------------	------------
<S>	<C>	<C>	<C>
Production:			
Oil (MBbls)	226	273	232
Gas (MMcf)	14,215	13,566	13,943
Total production (MMcfe)	15,571	15,206	15,334
Average daily production (MMcfe)	42.7	41.7	41.9
Average sales price:			
Oil (per Bbl)	$ 23.11	$ 22.95	$ 27.88
Gas (per Mcf)	$ 3.94	$ 3.96	$ 3.57
Total production (per Mcfe)	$ 3.93	$ 3.95	$ 3.67
Average costs (per Mcfe):			
Lease operating expenses	$ .71	$ .73	$ .61
Depletion	$ 1.73	$ 1.37	$ 1.10
General and administrative (net of management fees)	$ .30	$ .30	$ .27

</Table>

(a) Includes hedging gains and losses.

(b) Includes volumes of 1,200 MMcf for the year 2002 and 2,300 MMcf for each of the years 2001 and 2000, at an average price of $2.08 per Mcf associated with a volumetric production payment.

PENDING SEC REVIEW OF RESERVE INFORMATION

In October 2002 and February 2003, we received letters from the SEC regarding our Annual Report on Form 10-K for the year ended December 31, 2001 requesting supplemental information concerning our operations in the Gulf of Mexico. The comment letters requested information about the procedures we used to classify our deepwater reserves as proved and requested that our financials be restated to reflect the removal of the Boomslang reserves as proved for all prior periods during which such reserves were reported as proved. We have reviewed the SEC comments with our independent petroleum reserve engineers, Huddleston & Co., Inc. of Houston, Texas. Both Huddleston & Co and Callon believe that such deepwater reserves are properly classified as proved.

COMPARISON OF RESULTS OF OPERATIONS FOR THE YEARS ENDED DECEMBER 31, 2002 AND 2001

OIL AND GAS REVENUES

Oil and gas revenues for 2002 were $61.2 million, a 2% increase from the 2001 amount of $60.0 million. 2002 oil and gas production of 15,571 MMcfe increased as well from the 2001 amount of 15,206 MMcfe.

Oil production decreased from 273,000 barrels in 2001 to 226,000 barrels in 2002 but the average sales price increased from $22.95 in 2001 to $23.11 in 2002. As a result, oil revenues dropped from $6.3 million in 2001 to $5.2 million in 2002. The production decrease was primarily due to older properties' normal and expected decline in production.

Gas revenues for 2002 were $55.9 million based on sales of 14.2 Bcf at an average sales price of $3.94 per Mcf. For 2001, gas revenues were $53.7 million based on production of 13.6 Bcf sold at an average sales price of $3.96 per Mcf. Our gas production in 2002 increased when compared to last year due primarily to the acceleration program at Mobile Blocks 952/953/955 area initiated in the fourth quarter of 2001.

LEASE OPERATING EXPENSES

Lease operating expenses remained relatively stable at $11.3 million ($.73 per Mcfe) in 2001 compared to $11.0 million ($.71 per Mcfe) in 2002.

DEPRECIATION, DEPLETION AND AMORTIZATION

Depreciation, depletion and amortization increased by 28% due in large part to the downward reserve revisions at Boomslang. This decrease in estimated proved reserves, over which depletable costs are amortized, increased the per unit depletion rate, while production remained relatively constant between years.

Total charges increased from $21.1 million or $1.39 per Mcfe in 2001, to $27.1 million, or $1.74 per Mcfe in 2002.

GENERAL AND ADMINISTRATIVE

General and administrative expenses for 2002 were $4.7 million, or $.30 per Mcfe, compared to $4.6 million, or $.30 per Mcfe, in 2001.

INTEREST EXPENSE

Interest expense for 2002 was $26.1 million increasing from $12.8 million in 2001. This is a result of an increase in our long-term debt as well as higher interest rates associated with additional debt incurred in 2002.

INCOME TAXES

Our 2002 results include a deferred income tax benefit of $900,000. We evaluated the deferred income tax asset in light of our reserve quantity estimates, our long-term outlook for oil and gas prices and our expected level of future revenues and expenses. We believe it is more likely than not, based upon this evaluation, that we will realize the recorded deferred income tax asset. However, there is no assurance that such asset will ultimately be realized.

COMPARISON OF RESULTS OF OPERATIONS FOR THE YEARS ENDED DECEMBER 31, 2001 AND 2000

OIL AND GAS REVENUES

Oil and gas revenues for 2001 were $60.0 million, a 7% increase from the 2000 amount of $56.3 million. However, 2001 oil and gas production of 15,206 MMcfe decreased slightly from the 2000 amount of 15,334 MMcfe.

Oil production increased from 232,000 barrels in 2000 to 273,000 barrels in 2001 but the average sales price decreased from $27.88 in 2000 to $22.95 in 2001. As a result, oil revenues dropped from $6.5 million in 2000 to $6.3 million in 2001. The production increase was primarily from increased oil production at South Marsh Island 261 offset by older properties' normal and expected decline in production. The slight decrease in oil revenue was due to the decline in average oil prices received in 2001.

Gas revenues for 2001 were $53.7 million based on sales of 13.6 Bcf at an average sales price of $3.96 per Mcf. For 2000, gas revenues were $49.8 million based on production of 13.9 Bcf sold at an average sales price of $3.57 per Mcf. Our gas production in 2001 decreased when compared to last year as a result of

production declines at East Cameron 275 and South Marsh Island 261, offset by increases in production at Mobile Block 864 and Chandeleur Block 40. The production declines at East Cameron 275 and South Marsh Island 261 were normal and expected as the 2000 rates were indicative of higher initial production. The Mobile Block 864 Area increased production due to a well stimulation program as well additions to production through exploratory and developmental drilling on the property. Gas revenue increased due to higher prices received for production in 2001.

LEASE OPERATING EXPENSES

Lease operating expenses increased from $9.3 million ($.61 per Mcfe) in 2000 to $11.3 million ($.73 per Mcfe) in 2001. The increase was attributable to higher operating costs at South Marsh Island 261 and at Mobile Block 864. Also, production declines related to older properties that have relatively fixed operating costs contributed to the higher per Mcf costs with lower production levels for those properties in 2001.

WRITEDOWN OF ENRON DERIVATIVES

In April of 2001, we entered into derivative contracts for 2002 production with Enron North America Corp. Enron North America Corp. filed for protection under the bankruptcy laws in late 2001. As a result of the credit risk associated with the derivatives with Enron North America Corp., hedge accounting was not available due to ineffectiveness as of September 30, 2001 and the contracts at December 31, 2001 were marked to the market. In the fourth quarter of 2001, we charged to expense (non-cash) $9.2 million related to these Enron North America Corp. derivatives. We have no other contracts with Enron or their related subsidiaries.

DEPRECIATION, DEPLETION AND AMORTIZATION

Depreciation, depletion and amortization increased by 23% due to a combination of an increase in the amortization base due to higher drilling costs with reserve additions being less than expected from exploration efforts in 2001 and downward reserve revisions in 2000 as a result of a field delineation program at Habanero.

Total charges increased from $17.2 million, or $1.12 per Mcfe in 2000 to $21.1 million, or $1.39 per Mcfe in 2001.

GENERAL AND ADMINISTRATIVE

General and administrative expenses for 2001 were $4.6 million, or $.30 per Mcfe, compared to $4.2 million, or $.27 per Mcfe, in 2000. This increase was due primarily to expenses incurred in the second quarter of 2001 related to our withdrawn debt offering.

INTEREST EXPENSE

Interest expense for 2001 was $12.8 million increasing from $8.4 million in 2000. This is a result of an increase in our long-term debt as well as higher interest rates associated with additional debt incurred in 2001.

INCOME TAXES

Our 2001 results include a deferred income tax expense of $977,000. We evaluated the deferred income tax asset in light of our reserve quantity estimates, our long-term outlook for oil and gas prices and our expected level of future revenues and expenses. We believe it is more likely than not, based upon this evaluation, that we will realize the recorded deferred income tax asset. However, there is no assurance that such asset will ultimately be realized.

ITEM 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISKS

The Company's revenues are derived from the sale of its crude oil and natural gas production. In recent months, the prices for oil and gas have increased; however, they remain extremely volatile and sometimes experience large fluctuations as a result of relatively small changes in supplies, weather conditions, economic conditions and government actions. The Company enters into derivative financial instruments to hedge oil and gas price risks for the production volumes to which the hedge relates. The derivatives reduce the Company's exposure on the hedged volumes to decreases in commodity prices and limit the benefit the Company might otherwise have received from any increases in commodity prices on the hedged volumes.

The Company also enters into price "collars" to reduce the risk of changes in oil and gas prices. Under these arrangements, no payments are due by either party so long as the market price is above the floor price set in the collar and below the ceiling. If the price falls below the floor, the counter-party to the collar pays the difference to the Company and if the price is above the ceiling, the counter-party receives the difference from the Company. The Company enters into these various agreements to reduce the effects of volatile oil and gas prices and does not enter into hedge transactions for speculative purposes. See Note 6 to the Consolidated Financial Statements for a description of the Company's hedged position at December 31, 2002. There have been no significant changes in market risks faced by the Company since the end of 2002.

Based on projected annual sales volumes for 2003 (excluding forecast production increases over 2002), a 10% decline in the prices we receive for our crude oil and natural gas production would have an approximate $6.5 million impact on our revenues.

ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

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REPORT OF INDEPENDENT AUDITORS

The Stockholders and Board of Directors
Callon Petroleum Company:

We have audited the accompanying consolidated balance sheet of Callon Petroleum Company as of December 31, 2002, and the related consolidated statements of operations, stockholders' equity and cash flows for the year then ended. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audit. The financial statements of Callon Petroleum Company as of December 31, 2001 and for each of the two years in the period then ended, were audited by other auditors who have ceased operations and whose report dated March 29, 2002, expressed an unqualified opinion on those statements and included an explanatory paragraph that disclosed the change in the Company's method of accounting for derivative instruments and hedging activities discussed in Note 2 to those financial statements.

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

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

ERNST & YOUNG LLP

New Orleans, Louisiana
February 28, 2003

The following report is a copy of the audit report previously issued by Arthur Andersen LLP in connection with Callon Petroleum Company's annual report on Form 10-K for the year ended December 31, 2001. This audit report has not been reissued by Arthur Andersen LLP in connection with this filing on form 10-K for the year ended December 31, 2002. The consolidated balance sheet as of December 31, 2000 and the consolidated statements of operations, stockholders' equity and cash flows for the year ended December 31, 1999, mentioned in the report, are not required in the Company's annual report for 2002 and are therefore not presented among the financial statements in this annual report.

REPORT OF INDEPENDENT AUDITORS

To the Stockholders and Board of Directors of Callon Petroleum Company:

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

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

In our opinion, the financial statements referred to above present fairly, in all material respects, the financial position of Callon Petroleum Company and subsidiaries, as of December 31, 2001 and 2000, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2001, in conformity with accounting principles generally accepted in the United States.

As discussed in Note 2 to the consolidated financial statements effective January 1, 2001, the Company adopted SFAS 133, "Accounting for Derivative Instruments and Hedging Activities."

ARTHUR ANDERSEN LLP

New Orleans, Louisiana
March 29, 2002

CALLON PETROLEUM COMPANY
CONSOLIDATED BALANCE SHEETS
(IN THOUSANDS, EXCEPT SHARE DATA)

<Table>
<Caption>

	DECEMBER 31,	
	2002	2001
<S>	<C>	<C>
ASSETS		
Current assets:		
Cash and cash equivalents	$ 5,807	$ 6,887
Accounts receivable	10,875	5,908
Other current assets	570	209
Total current assets	17,252	13,004
Oil and gas properties, full-cost accounting method:		
Evaluated properties	762,918	704,937
Less accumulated depreciation, depletion and amortization	(426,254)	(399,339)
	336,664	305,598
Unevaluated properties excluded from amortization	40,997	37,560
Total oil and gas properties	377,661	343,158
Pipeline and other facilities, net	853	5,364
Other property and equipment, net	1,890	2,455
Deferred tax asset	8,767	4,399
Long-term gas balancing receivable	761	473
Other assets, net	3,429	3,242
Total assets	$ 410,613	$ 372,095
LIABILITIES AND STOCKHOLDERS' EQUITY		
Current liabilities:		
Accounts payable and accrued liabilities	$ 12,498	$ 9,985
Undistributed oil and gas revenues	1,109	1,131
Accrued net profits interest payable	1,707	1,501
Accounts payable and accrued liabilities to be refinanced	--	9,558
Current maturities of long-term debt	1,320	37,345
Total current liabilities	16,634	59,520
Long-term debt-excluding current maturities	248,269	161,733
Accounts payable and accrued liabilities to be refinanced	3,861	--
Deferred revenue on sale of production payment	--	2,406
Accrued retirement benefits	204	137
Long-term gas balancing payable	685	1,075
Total liabilities	269,653	224,871
Stockholders' equity:		
Preferred Stock, $.01 par value; 2,500,000 shares authorized; 600,861 shares of Convertible Exchangeable Preferred Stock, Series A issued and outstanding at December 31, 2002 with a liquidation preference of $15,021,525	6	6
Common Stock, $.01 par value; 20,000,000 shares		

authorized; 13,900,466 shares and 13,397,706 shares outstanding at December 31, 2002 and 2001, respectively	139	134
Capital in excess of par value	158,370	154,425
Unearned restricted stock compensation	(826)	--
Accumulated other comprehensive income (loss)	(469)	5,971
Retained earnings (deficit)	(16,260)	(13,312)
Total stockholders' equity	140,960	147,224
Total liabilities and stockholders' equity	$ 410,613	$ 372,095

</Table>

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

CALLON PETROLEUM COMPANY
CONSOLIDATED STATEMENTS OF OPERATIONS
FOR THE YEARS ENDED DECEMBER 31, 2002, 2001 AND 2000
(IN THOUSANDS, EXCEPT PER SHARE AMOUNTS)

<Table>
<Caption>

<S>	2002 <C>	2001 <C>	2000 <C>
Revenues:			
Oil and gas sales	$ 61,171	$ 60,010	$ 56,310
Interest and other	1,004	1,742	1,767
Gain on sale of pipeline	2,454	--	--
Gain on sale of Enron derivatives	2,479	--	--
Total revenues	67,108	61,752	58,077
Costs and expenses:			
Lease operating expenses	11,030	11,252	9,339
Depreciation, depletion and amortization	27,096	21,081	17,153
General and administrative	4,705	4,635	4,155
Writedown of Enron derivatives	--	9,186	--
Loss on mark-to-market commodity derivative contracts	708	--	--
Interest	26,140	12,805	8,420
Total costs and expenses	69,679	58,959	39,067
Income (loss) from operations	(2,571)	2,793	19,010
Income tax expense (benefit)	(900)	977	6,463
Net income (loss)	(1,671)	1,816	12,547
Preferred stock dividends	1,277	1,277	2,403
Net income (loss) available to common shares	$ (2,948)	$ 539	$ 10,144
Net income (loss) per common share:			
Basic	$ (.22)	$ .04	$ .82
Diluted	$ (.22)	$ .04	$ .80
Shares used in computing net income (loss) per common share:			
Basic	13,387	13,273	12,420

Diluted	13,387	13,366	12,745
	============	============	============

</Table>

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

CALLON PETROLEUM COMPANY
CONSOLIDATED STATEMENTS OF STOCKHOLDERS' EQUITY
(IN THOUSANDS)

<Table>
<Caption>

<S>	Preferred Stock <C>	Common Stock <C>	Unearned Restricted Stock Compensation <C>	Capital in Excess of Par Value <C>	Accumulated Other Comprehensive Income (Loss) <C>	Retained Earnings (Deficit) <C>	Total Stock-holders' Equity <C>
Balances, December 31, 1999	$ 11	$ 122	$ --	$ 148,242	$ --	$ (23,995)	$ 124,380
Net income	--	--	--	--	--	12,547	12,547
Preferred stock dividends	--	--	--	--	--	(1,978)	(1,978)
Shares issued pursuant to employee benefit and option plan	--	--	--	1,069	--	--	1,069
Employee stock purchase plan	--	--	--	269	--	--	269
Tax benefits related to stock compensation plans	--	--	--	41	--	--	41
Conversion of preferred shares to common stock	(5)	11	--	419	--	(425)	--
Balances, December 31, 2000	6	133	--	150,040	--	(13,851)	136,328
Comprehensive income:							
Net income	--	--	--	--	--	1,816	
Other comprehensive income	--	--	--	--	5,971	--	
Total comprehensive income							7,787
Preferred stock dividend	--	--	--	--	--	(1,277)	(1,277)
Shares issued pursuant to employee benefit and option plan	--	1	--	942	--	--	943
Employee stock purchase plan	--	--	--	357	--	--	357
Tax benefits related to stock compensation plans	--	--	--	18	--	--	18
Warrants	--	--	--	3,068	--	--	3,068
Balances, December 31, 2001	6	134	--	154,425	5,971	(13,312)	147,224
Comprehensive income:							
Net loss	--	--	--	--	--	(1,671)	
Other comprehensive loss	--	--	--	--	(6,440)	--	
Total comprehensive loss							(8,111)
Preferred stock dividends	--	--	--	--	--	(1,277)	(1,277)
Shares issued pursuant to employee benefit and option plan	--	1	--	770	--	--	771
Employee stock purchase plan	--	--	--	79	--	--	79
Tax benefits related to stock compensation plans	--	--	--	(29)	--	--	(29)
Restricted stock	--	3	(826)	1,849	--	--	1,026
Warrants	--	1	--	1,276	--	--	1,277

Balances, December 31, 2002	$ 6	$ 139	$ (826)	$ 158,370	$ (469)	$ (16,260)	$ 140,960
	==========	==========	==========	==========	==========	=========	==========

</Table>

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

CALLON PETROLEUM COMPANY
CONSOLIDATED STATEMENTS OF CASH FLOWS
FOR THE YEARS ENDED DECEMBER 31, 2002, 2001 AND 2000
(IN THOUSANDS)

<Table>
<Caption>

	2002	2001	2000
<S>	<C>	<C>	<C>
Cash flows from operating activities:			
Net income (loss)	$ (1,671)	$ 1,816	$ 12,547
Adjustments to reconcile net income (loss) to cash provided by operating activities:			
Depreciation, depletion and amortization	27,774	21,709	17,598
Gain on sale of pipeline	(2,454)	--	--
Amortization of deferred costs	5,521	2,485	1,034
Non-cash derivative income	(9,186)	--	--
Mark-to-market commodity derivative contracts	708	--	--
Amortization of deferred production payment revenue	(2,406)	(4,830)	(4,844)
Writedown of Enron derivatives	--	9,186	--
Deferred income tax expense (benefit)	(900)	977	6,463
Non-cash charge related to compensation plans	1,267	942	1,069
Changes in current assets and liabilities:			
Accounts receivable	(4,967)	3,336	(3,882)
Advance to operators	(98)	1,131	(1,131)
Other current assets	(6)	(2)	(18)
Investment in derivative contracts	(1,687)	--	--
Current liabilities	3,198	(8,782)	1,077
Increase in accounts payable and accrued liabilities to be refinanced	--	9,558	--
Change in gas balancing receivable	(288)	170	(400)
Change in gas balancing payable	(390)	355	204
Change in other long-term liabilities	67	(1,749)	(221)
Change in other assets, net	(2,315)	(1,071)	(751)
Cash provided (used) by operating activities	12,167	35,231	28,745
Cash flows from investing activities:			
Capital expenditures	(66,023)	(113,833)	(81,849)
Proceeds from sale of pipeline	6,784	--	--
Cash proceeds from sale of mineral interests	4,492	1,195	--
Cash provided (used) by investing activities	(54,747)	(112,638)	(81,849)
Cash flows from financing activities:			
Decrease in accounts payable and accrued liability to be refinanced	(5,697)	--	--
Equity issued related to employee stock plans	79	357	269
Payment on debt	(58,085)	(84,900)	(29,250)
Increase in debt	109,900	155,000	63,000
Debt issuance costs	(2,291)	(2,374)	(1,496)
Capital lease	(1,129)	5,612	--
Cash dividends on preferred stock	(1,277)	(1,277)	(2,214)
Cash provided (used) by financing activities	41,500	72,418	30,309

Net increase (decrease) in cash and cash equivalents	(1,080)	(4,989)	(22,795)
Cash and cash equivalents:			
Balance, beginning of period	6,887	11,876	34,671
Balance, end of period	$ 5,807	$ 6,887	$ 11,876

</Table>

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

CALLON PETROLEUM COMPANY
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

1. ORGANIZATION

GENERAL

Callon Petroleum Company ("Company") was organized under the laws of the state of Delaware in March 1994 to serve as the surviving entity in the consolidation and combination of several related entities (referred to herein collectively as the "Constituent Entities"). The combination of the businesses and properties of the Constituent Entities with the Company was completed on September 16, 1994 ("Consolidation").

As a result of the Consolidation, all of the businesses and properties of the Constituent Entities are owned (directly or indirectly) by the Company. Certain registration rights were granted to the stockholders of certain of the Constituent Entities. See Note 7.

The Company and its predecessors have been engaged in the acquisition, development and exploration of crude oil and natural gas since 1950. The Company's properties are geographically concentrated in Louisiana, Alabama, Texas and offshore Gulf of Mexico.

LIQUIDITY AND CAPITAL RESOURCES

In 2002, the lenders under the Company's Credit Facility agreed to increase availability under the revolving borrowing base from $50 million to $75 million. In addition, the holders of $22.9 million of the $36.0 million of the Company's 10.125% Senior Subordinated Notes ("Notes") consented to an extension of such Notes until July 31, 2004. The Company granted 274,980 warrants with a fair market value of approximately $1.3 million to purchase Common Stock of the Company for $.01 per share and paid consent fees in the amount of $2.3 million to the holders of the Notes that granted the extensions. The holders of the Notes that did not consent to the extension were paid on the maturity date of the Notes in September 2002. Subsequent to September 2002, the holders of the Notes exercised approximately 116,000 warrants that were granted as a result of the extension of the Notes.

Non-discretionary capital expenditures include completion of the Medusa deepwater discovery, currently scheduled to begin production in the late summer of 2003. The Company anticipates that cash flow generated during 2003 and current availability under the Credit Facility will provide necessary capital to enable the Company to continue its operational activities until such time as production from the Medusa discovery begins. At that time, the Company anticipates that the Medusa reserves and production will be integrated into the borrowing base of the Company's Credit Facility and will provide additional available borrowing capacity. This increase in borrowing capacity as well as significant additional cash flow expected from the new production will provide funds for future discretionary capital expenditures.

Following Medusa, the Habanero deepwater discovery is scheduled for development and is projected to begin initial production in the second half of 2003. Once producing, this deepwater discovery is projected to have the same positive impact on borrowing capacity as Medusa. Habanero will be produced by the

existing delineation well and an additional well to be drilled in the summer of 2003. A sub sea completion will be routed into one of the operator's existing facilities and initial production is expected in late third quarter of 2003.

The completion of the Company's deepwater discoveries will require the construction of expensive production facilities and pipelines, including the transportation and installation of production facilities and the use of sub sea completion techniques. The Company cannot estimate the timing of the construction of these facilities with certainty. The operators completing these discoveries will possibly face inclement weather and other unfavorable environmental conditions, delays in fabrication and delivery of necessary equipment, and other unforeseen circumstances that may delay completion of these properties. Long-term delays in the completion of these deepwater projects that prevent the commencement of production from such discoveries could have a material adverse effect on the Company's financial position and result of operations. Such a delay would require the Company to reduce future anticipated capital expenditures or seek additional sources of liquidity to finance capital expenditures, which may not be available.

2. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

PRINCIPLES OF CONSOLIDATION AND REPORTING

The Consolidated Financial Statements include the accounts of the Company, and its subsidiary, Callon Petroleum Operating Company ("CPOC"). CPOC also has subsidiaries, namely Callon Offshore Production, Inc. and Mississippi Marketing, Inc. All intercompany accounts and transactions have been eliminated. Certain prior year amounts have been reclassified to conform to presentation in the current year.

USE OF ESTIMATES

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

ACCOUNTING PRONOUNCEMENTS

In June 1998, the Financial Accounting Standards Board issued Statement of Financial Accounting Standards No. 133 ("SFAS 133"), Accounting for Derivative Instruments and Hedging Activities. The Statement establishes accounting and reporting standards requiring that every derivative instrument, including certain derivative instruments embedded in other contracts, be recorded in the balance sheet as either an asset or liability measured at its fair value. The Company adopted SFAS 133 effective January 1, 2001. The cumulative effect of the accounting change, net of tax, recorded as other comprehensive loss was $3.8 million.

SFAS 133 requires the Company to report changes in the fair value of our derivative financial instruments that qualify as cash flow hedges in other comprehensive income, a component of stockholders' equity, until realized. See Note 6 for a discussion of our derivative financial instruments.

In June 2001, the Financial Accounting Standards Board approved Statement of Accounting Standards No. 143, Asset Retirement Obligations ("SFAS 143"). SFAS 143 addresses financial accounting and reporting for obligations associated with the retirement of tangible long-lived assets and the associated asset retirement costs. We will record the fair value of these obligations on January 1, 2003, as well as the related additional assets. The net difference between our previously recorded abandonment liability and the amounts estimated under SFAS 143, after taxes, is expected to total a gain of approximately $180,000, which will be recognized as a cumulative effect of a change in accounting principle and an expected abandonment liability for retirement obligations of approximately $26 million.

In December 2002, the Financial Accounting Standards Board issued Statement of Financial Accounting Standards No. 148 ("SFAS 148"), "Accounting for Stock-Based Compensation-Transition and Disclosure--an amendment of SFAS No. 123." SFAS 148 amends SFAS 123 to provide alternative methods of transition for a voluntary change to the fair value based method of accounting for stock-based employee compensation. In addition, this statement amends the disclosure requirements of SFAS 123 to require disclosures in both annual and interim financial statements about the method of accounting for stock-based employee compensation and the effect of the method used on the reported results. SFAS 148 is effective for the year ended December 31, 2002 and for interim financial statements commencing in 2003. The adoption of this pronouncement by the Company did not have an impact on our financial condition or results of operations.

PROPERTY AND EQUIPMENT

The Company follows the full cost method of accounting for oil and gas properties whereby all costs incurred in connection with the acquisition, exploration and development of oil and gas reserves, including certain overhead costs, are capitalized. Such amounts include the cost of drilling and equipping productive wells, dry hole costs, lease acquisition costs, delay rentals, interest capitalized on unevaluated leases and other costs related to exploration and development activities. Payroll and general and administrative costs capitalized include salaries and related fringe benefits paid to employees directly engaged in the acquisition, exploration and/or development of oil and gas properties as well as other directly identifiable general and administrative costs associated with such activities. Such capitalized costs ($9.6 million in 2002, $10.0 million in 2001 and $7.4 million in 2000) do not include any costs related to production or general corporate overhead. Costs associated with unevaluated properties, including capitalized interest on such costs, are excluded from amortization. Unevaluated property costs are transferred to evaluated property costs at such time as wells are completed on the properties, the properties are sold or management determines these costs have been impaired.

Costs of properties, including future development and net future site restoration, dismantlement and abandonment costs, which have proved reserves and those which have been determined to be worthless, are depleted using the unit-of-production method based on proved reserves. If the total capitalized costs of oil and gas properties, net of amortization, exceed the sum of (1) the estimated future net revenues from proved reserves at current prices and discounted at 10% and (2) the lower of cost or market of unevaluated properties (the full cost ceiling amount), net of tax effects, then such excess is charged to expense during the period in which the excess occurs. See Note 8.

Upon the acquisition or discovery of oil and gas properties, management estimates the future net costs to be incurred to dismantle, abandon and restore the property using geological, engineering and regulatory data available. Such cost estimates are periodically updated for changes in conditions and requirements. Such estimated amounts are considered as part of the full cost pool subject to amortization upon acquisition or discovery. Such costs are capitalized as oil and gas properties as the actual restoration, dismantlement and abandonment activities take place. As discussed above under Accounting Pronouncements, beginning January 1, 2003, the Company will change the method for which we account for such cost as described by FAS 143.

Depreciation of other property and equipment is provided using the straight-line method over estimated lives of three to 20 years. Depreciation of pipeline and other facilities is provided using the straight-line method over estimated lives of 15 to 27 years.

SALE OF PRODUCTION PAYMENT INTEREST

In June 1999, the Company acquired a working interest in the Mobile Block 864 Area where the Company already owned an interest. Concurrent with this acquisition, the seller received a volumetric production payment, valued at approximately $14.8 million, from production attributable to a portion of the Company's interest in the area over a 39-month period. The Company recorded a liability associated with the sale of this production payment interest because a substantial obligation for future performance existed. Under the terms of the sale, the Company was obligated to deliver the production volumes free and clear of royalties, lease operating expenses, production taxes and all capital costs. The production payment was amortized, beginning in June 1999, to oil and gas sales on the units-of-production method as associated hydrocarbons were delivered, and expired in July 2002.

NATURAL GAS IMBALANCES

The Company follows an entitlement method of accounting for its proportionate share of gas production on a well-by-well basis, recording a receivable to the extent that a well is in an "undertake" position and conversely recording a liability to the extent that a well is in an "overtake" position. Imbalance positions are not significant at December 31, 2002.

DERIVATIVES

The Company uses derivative financial instruments for price protection purposes on a limited amount of its future production and does not use them for trading purposes. Such derivatives were accounted for, prior to adoption of SFAS 133, as hedges and have been recognized as an adjustment to oil and gas sales in the period in which they are related. Current accounting treatment is under SFAS 133 (see Note 6).

ACCOUNTS RECEIVABLE

Accounts receivable consists primarily of accrued oil and gas production receivables. The balance in the reserve for doubtful accounts included in accounts receivable was $143,000 and $68,000 at December 31, 2002 and 2001, respectively. Net recoveries were $75,000 in 2002 and net charge offs were $10,000 in 2001. There were no provisions to expense in the three-year period ended December 31, 2002.

ACCOUNTS PAYABLE AND ACCRUED LIABILITIES TO BE REFINANCED

These amounts included in the Balance Sheet represent capital expenditures in accounts payable and accrued liabilities that were refinanced with the availability under the Credit Facility subsequent to December 31, 2002. Amounts in 2001 were classified as short term because of the maturity of the Credit Facility at December 31, 2001. See Footnote 5 for a discussion of the amendment to the Credit Facility in June of 2001.

STOCK BASED COMPENSATION

The Company accounts for its stock based compensation plans under the recognition and measurement principles of APB Opinion No. 25, Accounting for Stock Issued to Employees, and related Interpretations. See Footnote 10 for descriptions and additional disclosures related to the plans.

MAJOR CUSTOMERS

Our production is sold generally on month-to-month contracts at prevailing prices. The following table identifies customers to whom we sold a significant percentage of our total oil and gas production during each of the twelve-month periods ended:

<Table>
<Caption>
DECEMBER 31,

	2002	2001	2000
Adams Resources Marketing, Ltd.	--	--	14%
Petrocom Energy Group, Ltd.	4%	--	--
Dynegy	7%	8%	--
Prior Energy Corporation	--	20%	--
Reliant Energy Services	70%	49%	37%
Unocal Exploration Corporation	--	--	8%

Because alternative purchasers of oil and gas are readily available, we believe that the loss of any of these purchasers would not result in a material adverse effect on our ability to market future oil and gas production.

STATEMENTS OF CASH FLOWS

For purposes of the Consolidated Financial Statements, the Company considers all highly liquid investments purchased with an original maturity of three months or less to be cash equivalents.

The Company paid no federal income taxes for the three years ended December 31, 2002. During the years ended December 31, 2002, 2001 and 2000, the Company made cash payments for interest of $25,507,000, $16,441,000 and $11,449,000 respectively.

PER SHARE AMOUNTS

Basic income or loss per common share was computed by dividing net income or loss by the weighted average number of shares of common stock outstanding during the year. Diluted income or loss per common share was determined on a weighted average basis using common shares issued and outstanding adjusted for the effect of stock options considered common stock equivalents computed using the treasury stock method. The conversion of the preferred stock was not included in any annual calculation due to its antidilutive effect on diluted income or loss per common share.

A reconciliation of the basic and diluted per share computation is as follows (in thousands, except per share amounts):

	2002	2001	2000
(a) Net income (loss) available for common stock	$ (2,948)	$ 539	$ 10,144
Preferred dividends assuming conversion of preferred stock (if dilutive)	--	--	--
(b) Income (loss) available for common stock assuming conversion of preferred stock (if dilutive)	$ (2,948)	$ 539	$ 10,144
(c) Weighted average shares outstanding	13,387	13,273	12,420
Dilutive impact of stock options	--	27	325
Dilutive impact of warrants	--	66	--
Convertible preferred stock (if dilutive)	--	--	--
(d) Total diluted shares	13,387	13,366	12,745
Stock options and warrants excluded due to antidilutive impact	2,945	1,438	150
Basic income (loss) per share (a/c)	$ (.22)	$ .04	$ .82
Diluted income (loss) per share (b/d)	$ (.22)	$ .04	$ .80

FAIR VALUE OF FINANCIAL INSTRUMENTS

Fair value of cash, cash equivalents, accounts receivable, accounts payable, the capital lease and the Credit Facility approximates book value at December 31, 2002 and 2001. Fair value of long-term debt (specifically, the 10.125%, the 10.25%, the 11% Senior Subordinated Notes and the 12% Senior Notes) have an estimated fair value of between 84% and 86% of face value at December 31, 2002.

3. INCOME TAXES

The Company follows the asset and liability method of accounting for deferred income taxes prescribed by Statement of Financial Accounting Standards No. 109 ("SFAS 109") "Accounting for Income Taxes". The statement provides for the recognition of a deferred tax asset for deductible temporary timing differences, capital and operating loss carryforwards, statutory depletion carryforward and tax credit carryforwards, net of a "valuation allowance". The valuation allowance is provided for that portion of the asset, for which it is deemed more likely than not, that it will not be realized. The Company's management determined that no valuation allowance was required in 2002 or 2001. Accordingly, the Company has recorded a deferred tax asset at December 31, 2002 and 2001 as follows:

<Table>
<Caption>

	DECEMBER 31,	
	2002	2001
	(IN THOUSANDS)	
<S>	<C>	<C>
Federal net operating loss carryforwards	$ 42,464	$ 29,723
Statutory depletion carryforward	4,251	4,184
Temporary differences:		
Oil and gas properties	(39,159)	(28,685)
Pipeline and other facilities	(299)	(1,822)
Non-oil and gas property	(30)	(62)
Other	1,540	1,061
Total tax asset	8,767	4,399
Valuation allowance	--	--
Net tax asset	$ 8,767	$ 4,399

</Table>

At December 31, 2002, the Company had, for federal tax reporting purposes, net operating loss carryforwards of $121.3 million, which expire in 2003 through 2017. Net operating loss carryforwards includes approximately $1.4 million of the total that will expire within the next five years including approximately $1 million in 2003. Additionally, the Company had available for tax reporting purposes $12.0 million in statutory depletion deductions, which can be carried forward for an indefinite period. No valuation allowance has been provided against these carryforwards because management believes that it is more likely than not they will be realized. However, realization is not assured.

The Company has significant state net operating loss carryforwards that are not included in the deferred tax asset above, as the Company does not anticipate generating taxable state income in the states in which these loss carryforwards apply. The Company has very limited state taxable income as primarily all of its revenue is generated in federal waters not subject to state income taxes.

The provision for income taxes at the Company's effective tax rate approximated the provision for income taxes at the statutory rate.

4. OTHER COMPREHENSIVE INCOME

The Company did not have any items of other comprehensive income prior to 2001. A recap of the Company's 2002 and 2001 comprehensive income (net of tax) is shown below (in thousands):

<Table>
<Caption>

YEARS ENDED DECEMBER,

	2002	2001
<S>	<C>	<C>
Other comprehensive income (loss):		
Cumulative effect of change in accounting principle	$ --	$ (3,764)
Change in unrealized derivatives' fair value	(469)	9,735
Amortization of Enron derivatives	(5,971)	--
Total other comprehensive income (loss)	$ (6,440)	$ 5,971

</Table>

5. LONG-TERM DEBT

Long-term debt consisted of the following at:

<Table>
<Caption>

	DECEMBER 31, 2002	DECEMBER 31, 2001
	(IN THOUSANDS)	
<S>	<C>	<C>
Credit Facility	$ 65,000	$ 100
Senior Notes, net of discount	87,020	84,366
10.125% Senior Subordinated Notes (due 2004), net of discount	20,086	36,000
10.25% Senior Subordinated Notes (due 2004)	40,000	40,000
11% Senior Subordinated Notes (due 2005)	33,000	33,000
Capital lease	4,483	5,612
	249,589	199,078
Less: current portion	1,320	37,345
	$ 248,269	$ 161,733

</Table>

The Company negotiated its Credit Facility effective October 31, 2000 with First Union National Bank. Borrowings under the Credit Facility are secured by mortgages covering substantially all of the Company's producing oil and gas properties. On June 30, 2002, the Company amended the Credit Facility to increase availability under the revolving borrowing base from $50 million to $75 million under a dual tranche loan. The Tranche A revolver bears interest at 0.25% to 0.75% above a defined base rate depending on utilization of the borrowing base or, at the option of the Company, LIBOR plus 2% to 2.5% based on utilization of the borrowing base and has a maximum aggregate credit amount of $45 million. The range of interest rates on the Tranche A revolver was 3.36% to 5.25% for the twelve months ended December 31, 2002. The Tranche B part of the facility will bear interest at 15% and has an aggregate maximum credit amount of $30 million. The amended Credit Facility contains substantially the same covenants as the original Credit Facility. The weighted average interest rate for the Credit Facility debt outstanding at December 31, 2002 and 2001 was 9.00% and 4.75%, respectively. Under the Credit Facility, a commitment fee of 0.25% or 0.375% per annum, depending on the amount of the unused portion of the borrowing base, is payable quarterly. The maturity date of the Credit Facility is June 30, 2004 and the $75 million borrowing base is subject to semi-annual re-determinations in April and October of each year.

On September 15, 2002, $36 million of the Company's 10.125% Senior Subordinated Notes ("Notes")that were issued on July 31, 1997, were due. The holders of $22.9 million of the Notes consented to an extension of such Notes until July 31, 2004. The Company granted 274,980 warrants (with a fair market value of approximately $1.3 million) to purchase Common Stock of the Company and paid consent fees in the amount of $2.3 million to the holders of the Notes that granted the extensions. The warrants have a term of five years and an exercise price of $0.01. The holders of the Notes had exercised approximately 116,000 warrants as of December 31, 2002. The holders of the Notes that did not consent to the extension were paid on the maturity date in September 2002. Interest on the Notes is payable quarterly, on March 15, June 15, September 15, and December 15 of each year.

The Company accounted for the extension of the $22.9 million in Notes described above as an extinguishment of the Notes and the issuance of new securities recorded at a fair value of $19.3 million.

The net loss on extinguishment, including the warrants and fees paid described above was not significant. Costs deferred with the extensions will be amortized through July 2004.

On July 15, 1999, the Company completed the sale of $40 million of Senior Subordinated Notes due 2004 at 10.25%. The net proceeds of approximately $38.2 million were used to pay down the Credit Facility at that time. These notes are not entitled to any mandatory sinking fund payments and are subject to redemption at the Company's option at par plus unpaid interest at any time after March 15, 2001. The notes are listed on the New York Stock Exchange under the symbol "CPE 04" and are subject to a change of control clause that obligates the Company to repurchase the notes for 101% of par should a change of control occur. Interest is paid quarterly.

The Company completed the sale of $33 million of 11% Senior Subordinated Notes due 2005, on October 26, 2000. The Company netted $31.5 million from the offering after deducting the underwriters' discount and offering expenses. Approximately $20.8 million of the net proceeds from the offering were used to purchase a portion of the Company's outstanding 10% Senior Subordinated Notes due 2001 in conjunction with a tender offer. The Company redeemed the remaining $3.4 million of its 10% Senior Subordinated Notes due 2001 not tendered in the offer.

In July 2001, the Company entered into a $95 million multiple advance term loan ("Senior Notes") with a private lender. The Company issued $45 million of 12% Senior Notes upon closing of the loan and issued the remaining $50 million of Senior Notes in December 2001. Under the terms of the agreement Callon also issued warrants to purchase, at a nominal exercise price, 265,210 shares of its common stock (fair value of $3.1 million) and conveyed an overriding royalty interest equal to 2% of the Company's net interest in four existing deepwater discoveries (fair value of $5.9 million). The warrants and the overriding royalty interest were earned by the lender based on the ratio of the amount of the loan proceeds advanced to the total loan facility amount. The Senior Notes will mature March 31, 2005, have an effective interest rate of approximately 16% and contain restrictions on certain types of future indebtedness.

In December 2001, the Company entered into a ten-year gas processing agreement associated with a production facility on Callon's Mobile 952 field with Hanover Compression Limited Partnership, which is being accounted for as a capital lease. Total minimum obligations are $8.4 million with interest representing approximately $2.8 million and the present value minimum obligations were $5.6 million ($1.2 million current).

Future minimum lease payments and debt maturities (in thousands) are as follows:

<Table>
<Caption>

YEAR	CAPITAL LEASE PAYMENTS	DEBT
<S>	<C>	<C>
2003	$ 1,998	$ --
2004	1,890	128,000
2005	822	128,000
2006	439	--
2007	348	--
Thereafter	923	--

</Table>

The Credit Facility, the subordinated debt and the Senior Notes contain various covenants including restrictions on additional indebtedness and payment of cash dividends as well as maintenance of certain financial ratios. The Company is in compliance with these covenants at December 31, 2002.

6. DERIVATIVES

The Company periodically uses derivative financial instruments to manage oil and gas price risk. Settlements of gains and losses on commodity price contracts are generally based upon the difference between the contract price or prices specified in the derivative instrument and a NYMEX price or other cash or futures index price. As a result of these contracts, there was no effect on oil and gas revenue during 2002 and in 2001, $1,371,000 was recognized as additional oil and gas revenue.

In 2002, the Company purchased and sold various put options and call options and elected not to designate these derivative financial instruments as accounting hedges and accordingly, accounted for these contracts under mark-to-market accounting. Year-to-date charges to income were $708,000.

During 2002, the Company entered into no-cost natural gas collar contracts in effect for February 2003 through October 2003. These agreements are for volumes of 275,000 Mcf per month with an average ceiling price of $4.79 and a floor price of $3.52. These contracts are accounted for as cash flow hedges under SFAS 133. The fair value of these collar contracts at December 31, 2002, recorded on the balance sheet is $721,350 and $468,878 (net of tax) as other comprehensive income.

In April 2001, the Company entered into derivative contracts for 2002 production with Enron North America Corp. These agreements are for average gas volumes of approximately 600,000 Mcf per month in 2002 with a weighted average ceiling price of $6.09 and floor price of $4.11. Enron North America Corp. filed for protection under the bankruptcy laws in late 2001. As a result of the credit risk associated with the derivatives with Enron North America Corp., hedge accounting was not available due to ineffectiveness as of September 30, 2001 and the contracts at December 31, 2001 were marked to the market. In the fourth quarter of 2001, the Company charged to expense (non-cash) $9.2 million related to these Enron North America Corp. derivatives. The Company has no other contracts with Enron or its subsidiaries.

The $5,971,000 (net of tax) recorded in other comprehensive income at December 31, 2001 is related to the fair value as of September 30, 2001 of the natural gas collar contracts with Enron North America Corp., which matured in 2002. As the contracts matured, the Company recorded non-cash revenue each month, offsetting the amounts in other comprehensive income related to the derivatives. The Company recorded approximately $1.7 million related to these Enron derivatives in the fourth quarter of 2002 and $9.2 million for the year ended December 31, 2002 as oil and gas revenue.

In the second quarter of 2002, the Company completed the sale of its claim against Enron for hedging transactions for $2.5 million in cash. As a result of the sale, the Company reported a pre-tax gain of $2.5 million in the second quarter of 2002.

The Company has no other derivative contracts.

7. COMMITMENTS AND CONTINGENCIES

As described in Note 9, abandonment trusts (the "Trusts") have been established for future abandonment obligations of those oil and gas properties of the Company burdened by a net profits interest. The management of the Company believes the Trusts will be sufficient to offset those future abandonment liabilities; however, the Company is responsible for any abandonment expenses in excess of the Trusts' balances. As of December 31, 2002, total estimated site restoration, dismantlement and abandonment costs were approximately $6,896,000, net of expected salvage value. Substantially all such costs are expected to be funded through the Trusts' funds, all of which will be accessible to the Company when abandonment work begins. In addition, as a working interest owner and/or operator of oil and gas properties, the Company is responsible for the cost of abandonment of such properties. See Note 2.

From time to time, the Company, as part of the Consolidation and other capital transactions, entered into Registration Rights Agreements whereby certain parties to the transactions are entitled to require the Company to register Common Stock of the Company owned by them with the Securities and Exchange Commission for sale to the public in firm commitment public offerings and generally to include shares owned by them, at no cost, in registration statements filed by the Company. Costs of the offering will not include broker's discounts and commissions, which will be paid by the respective sellers of the Common Stock.

The Company is involved in various claims and lawsuits incidental to its business. In the opinion of management, the ultimate liability thereunder, if any, will not have a material adverse effect on the financial position or results of operations of the Company.

The Company's activities are subject to federal, state and local laws and regulations governing environmental quality and pollution control. Although no assurances can be made, the Company believes that, absent the occurrence of an extraordinary event, compliance with existing federal, state and local laws, rules and regulating the release of materials in the environment or otherwise relating to the protection of the environment will not have a material effect upon the capital expenditures, earnings or the competitive position of the Company with respect to its existing assets and operations. The Company cannot predict what effect additional regulation or legislation, enforcement polices thereunder, and claims for damages to property, employees, other persons and the environment resulting from the Company's operations could have on its activities.

8. OIL AND GAS PROPERTIES

The following table discloses certain financial data relating to the Company's oil and gas activities, all of which are located in the United States.

<Table>
<Caption>

	YEARS ENDED DECEMBER 31,		
	2002	2001	2000
	(IN THOUSANDS)		
<S>	<C>	<C>	<C>
Capitalized costs incurred:			
Evaluated Properties-			
Beginning of period balance	$ 704,937	$ 589,549	$ 511,689
Property acquisition costs	1,471	1,713	3,211
Exploration costs	17,851	85,782	51,837
Development costs	43,151	34,980	25,242
Sale of mineral interests	(4,492)	(7,087)	(2,430)
End of period balance	$ 762,918	$ 704,937	$ 589,549
Unevaluated Properties (excluded from amortization) -			
Beginning of period balance	$ 37,560	$ 47,653	$ 44,434
Additions	5,802	8,760	9,417
Capitalized interest	5,289	4,879	4,548
Transfers to evaluated	(7,654)	(23,732)	(10,746)

End of period balance	$ 40,997	$ 37,560	$ 47,653
	==========	==========	==========
Accumulated depreciation, depletion and amortization			
Beginning of period balance	$ 399,339	$ 378,589	$ 361,758
Provision charged to expense	26,915	20,750	16,831
	----------	----------	----------
End of period balance	$ 426,254	$ 399,339	$ 378,589
	==========	==========	==========

</Table>

Unevaluated property costs, primarily lease acquisition costs incurred at federal lease sales, unevaluated drilling costs, capitalized interest and general and administrative costs being excluded from the amortizable evaluated property base consisted of $9.4 million incurred in 2002, $7.5 million incurred in 2001 and $24.1 million incurred in 2000 and prior. These costs are directly related to the acquisition and evaluation of unproved properties and major development projects. The excluded costs and related reserves are included in the amortization base as the properties are evaluated and proved reserves are established or impairment is determined. The Company expects that the majority of these costs will be evaluated over the next three to five year period.

Depletion per unit-of-production (thousand cubic feet of gas equivalent) amounted to $1.73, $1.37 and $1.10 for the years ended December 31, 2002, 2001, and 2000, respectively.

Under the full cost accounting rules of the SEC, the Company reviews the carrying value of its proved oil and gas properties each quarter. Under these rules, capitalized costs of proved oil and gas properties net of accumulated depreciation, depletion and amortization (DD&A) and deferred income taxes, may not exceed the present value of estimated future net cash flows from proved oil and gas reserves, discounted at 10 percent, plus the lower of cost or fair value of unproved properties included in the costs being amortized, net of related tax effects. These rules generally require pricing future oil and gas production at the unescalated market price for oil and gas at the end of each fiscal quarter and require a write-down if the "ceiling" is exceeded, unless prices recover sufficiently before the date of the auditor's report. Given the volatility of oil and gas prices, it is reasonably possible that the Company's estimate of discounted future net cash flows from proved oil and gas reserves could change in the near term. If oil and gas priced decline significantly, even if only for a short period of time, it is possible that writedowns of oil and gas properties could occur in the future.

9. NET PROFITS INTEREST

From 1989 through 1994, the Constituent Entities entered into separate agreements to purchase certain oil and gas properties with gross contract acquisition prices of $170,000,000 ($150,000,000 net as of closing dates) and in simultaneous transactions, entered into agreements to sell overriding royalty interests ("ORRI") in the acquired properties. These ORRI are in the form of net profits interests ("NPI") equal to a significant percentage of the excess of gross proceeds over production costs, as defined, from the acquired oil and gas properties. A net deficit incurred in any month can be carried forward to subsequent months until such deficit is fully recovered. The Company has the right to abandon the purchased oil and gas properties if it deems the properties to be uneconomical.

The Company has, pursuant to the purchase agreements, created abandonment trusts whereby funds are provided out of gross production proceeds from the properties for the estimated amount of future abandonment obligations related to the working interests owned by the Company. The Trusts are administered by unrelated third party trustees for the benefit of the Company's working interest in each property. The Trust agreements limit their funds to be disbursed for the satisfaction of abandonment obligations. Any funds remaining in the Trusts after all restoration, dismantlement and abandonment obligations have been met will be distributed to the owners of the properties in the same ratio as contributions to the Trusts. The Trusts' assets are excluded from the Consolidated Balance Sheets of the Company because the Company does not control the Trusts. Estimated future revenues and costs associated with the NPI and the Trusts are also excluded from the oil and gas reserve disclosures at Note 12. As of December 31, 2002 and 2001, the Trusts' assets (all cash and investments) totaled $6,896,000 and $6,567,000 respectively, all of which will be available to the Company to pay its portion, as working interest owner, of the restoration, dismantlement and abandonment costs discussed at Note 7. FAS 143, discussed in Footnote 2, will require the Abandonment Trusts' assets and the associated abandonment liability to be recorded in the balance sheet effective January 1, 2003. The Company does not expect to record any income or loss associated with the Trust asset or abandonment liability as a result of adoption of FAS 143.

At the time of acquisition of properties by the Company, the property owners estimated the future costs to be incurred for site restoration, dismantlement and abandonment, net of salvage value. A portion of the amounts necessary to pay such estimated costs was deposited in the Trusts upon acquisition of the properties, and the remainder is deposited from time to time out of the proceeds from production. The determination of the amount deposited upon the acquisition of the properties and the amount to be deposited as proceeds from production was based on numerous factors, including the estimated reserves of the properties. The amounts deposited in the Trusts upon acquisition of the properties were capitalized by the Company as oil and gas properties.

As operator, the Company receives all of the revenues and incurs all of the production costs for the purchased oil and gas properties but retains only that portion applicable to its net ownership share. As a result, the payables and receivables associated with operating the properties included in the Company's Consolidated Balance Sheets include both the Company's and all other outside owners' shares. However, revenues and production costs associated with the acquired properties reflected in the accompanying Consolidated Statements of Operations represent only the Company's share, after reduction for the NPI.

10. EMPLOYEE BENEFIT PLANS

The Company has adopted a series of incentive compensation plans designed to align the interest of the executives and employees with those of its stockholders. The following is a brief description of each plan:

The Savings and Protection Plan provides employees with the option to defer receipt of a portion of their compensation and the Company may, at its discretion, match a portion of the

employee's deferral with cash and Company Common Stock. The Company may also elect, at its discretion, to contribute a non-matching amount in cash and Company Common Stock to employees. The amounts held under the Savings and Protection Plan are invested in various funds maintained by a third party in accordance with the directions of each employee. An employee is fully vested, including Company discretionary contributions, immediately upon participation in the Savings and Protection Plan. The total amounts contributed by the Company, including the value of the common stock contributed, were $611,000, $595,000 and $500,000 in the years 2002, 2001 and 2000, respectively.

The 1994 Stock Incentive Plan (the "1994 Plan"), approved by the shareholder's in 1994, provides for 600,000 shares of Common Stock to be reserved for issuance pursuant to such plan. Under the 1994 Plan, the Company may grant both stock options qualifying under Section 422 of the Internal Revenue Code and options that are not qualified as incentive stock options, as well as performance shares. These options have an expiration date 10 years from date of grant.

On August 23, 1996, the Board of Directors of the Company approved and adopted the Callon Petroleum Company 1996 Stock Incentive Plan (the "1996 Plan"). The 1996 Plan was approved by the shareholders in 1997 and provides for the same types of awards as the 1994 Plan and is limited to a maximum of 1,200,000 shares (as amended from the original 900,000 shares) of common stock that may be subject to outstanding awards. Unvested options are subject to forfeiture upon certain termination of employment events and expire 10 years from date of grant.

The Company granted 533,000 stock options to employees on March 23, 2000 and 120,000 stock options to directors on July 25, 2000 at $10.50 per share. The March 23, 2000 grant was subject to shareholder approval of an amendment to the 1996 Stock Incentive Plan. The amendment, which was approved on May 9, 2000 at the Annual Meeting of Shareholders, increased the number of shares reserved for issuance under the 1996 plan to 2,200,000 shares. The excess of the market price over the exercise price on the approval date of the amendment is amortized over the three-year vesting period of the options. Compensation costs of $416,000, $611,000 and $801,000 were recognized in 2002, 2001 and 2000 respectively related to these options.

On February 14, 2002, the Board of Directors of the Company approved and adopted the 2002 Stock Incentive Plan (the "2002 Plan"). Pursuant to the 2002 Plan, 350,000 shares of common stock shall be reserved for issuance upon the exercise of options or for grants of stock options, stock appreciation rights or units, bonus stock, or performance shares or units. This Plan qualifies as a "broadly based" plan under the provisions of the New York Stock Exchanges rules and regulations and therefore did not require shareholder approval. Because the 2002 Plan is a broadly based plan, the aggregate number of shares underlying awards granted to officer and directors cannot exceed 50% of the total number of shares underlying the awards granted to all employees during any three-year period.

In 2002, the Company awarded 300,000 shares of restricted stock from the 1996 and the 2002 Plan and 70,500 from treasury shares to be issued as vested. The issuance of the restricted stock using treasury shares did not require shareholder approval pursuant to the New York Stock Exchange's rules and regulations, and therefore shareholder approval was not sought. These shares will generally vest to the recipients over a three-year period (one-third in each year)

beginning in November 2002. The deferred compensation portion of this grant will be amortized to expense over the vesting period. The non-cash amortization expense in 2002 was $496,000.

In 1997, the Board of Directors authorized the implementation of the Callon Petroleum Company 1997 Employee Stock Purchase Plan (the "1997 Purchase Plan"), which was approved by the Company's shareholders at the 1997 Annual Meeting. The Plan provides eligible employees of the Company with the opportunity to acquire a proprietary interest in the Company through participation in a payroll deduction-based employee stock purchase plan. An aggregate of 250,000 shares of Common Stock have been reserved for issuance over the ten-year term of the 1997 Purchase Plan. The purchase price per share at which Common Stock will be purchased on the participant's behalf on each purchase date within an offering period is equal to eighty-five percent of the fair market value per share of Common Stock.

The Company accounts for the options issued pursuant to the stock incentive plans under APB Opinion No. 25, under which no compensation cost has been recognized unless the exercise price is less than the market price at the measurement date. Had compensation cost for these plans been determined consistent with Statement of Financial Accounting Standards No. 123 ("SFAS 123"), "Accounting for Stock-Based Compensation", the Company's net income and earnings per common share would have been reduced to the following pro forma amounts:

<Table>
<Caption>

	2002	2001	2000
	(IN THOUSANDS, EXCEPT PER SHARE DATA)		
<S>	<C>	<C>	<C>
Net income (loss), as reported	$ (2,948)	$ 539	$ 10,144
Deduct total stock-based employee Compensation expense under fair			

value based method, net of tax	637	1,378	1,726
Pro forma net income (loss)	(3,585)	(839)	8,418
Basic earnings (loss) per share: As Reported	(.22)	.04	.82
Pro Forma	(.27)	(.06)	.68
Diluted earnings (loss) per share: As Reported	(.22)	.04	.80
Pro Forma	(.27)	(.06)	.66

</Table>

A summary of the status of the Company's stock option plans for the three most recent years and changes during the years then ended is presented in the table and narrative below:

<Table>
<Caption>

	2002		2001		2000	
	SHARES	WTD AVG EX PRICE	SHARES	WTD AVG EX PRICE	SHARES	WTD AVG EX PRICE
<S>	<C>	<C>	<C>	<C>	<C>	<C>
Outstanding, beginning of year	2,332,667	$ 10.84	2,304,167	$ 10.83	1,536,500	$ 10.60
Granted (at market)	310,000	4.45	30,000	11.61	135,000	14.73
Granted (below market)	--	--	--	--	653,000	10.50
Exercised	--	--	(1,500)	9.00	(20,333)	9.00
Forfeited	(122,250)	14.10	--	--	--	--
Expired	--	--	--	--	--	--
Outstanding, end of year	2,520,417	$ 9.90	2,332,667	$ 10.84	2,304,167	$ 10.83
Exercisable, end of year	2,224,334	$ 10.57	2,057,977	$ 10.80	1,647,657	$ 10.71
Weighted average fair value of options granted (at market)	$ 2.44		$ 5.80		$ 7.68	
Weighted average fair value of options granted (below market)	N/A		N/A		$ 7.90	

</Table>

The following table sets forth additional information regarding options outstanding at December 31, 2002. Contractual life and exercise prices represent weighted averages for options outstanding and options exercisable.

<Table>
<Caption>

	Options Outstanding			Options Exercisable	
Range of exercise prices	Number Outstanding	Contractual Life (years)	Exercise Price	Number Exercisable	Exercise Price
<S>	<C>	<C>	<C>	<C>	<C>
$ 3.70 to $ 6.41	297,750	9.6	$ 4.38	31,667	$ 6.07
$ 9.00 to $ 12.28	2,157,667	4.9	$ 10.53	2,127,667	$ 10.53
$ 13.56 to $ 15.31	65,000	5.3	$ 14.16	65,000	$ 14.16

</Table>

The fair value of each option grant is estimated on the date of grant using the Black-Scholes option pricing model with the following weighted average assumptions used for options granted during the years presented are as follows:

<Table>
<Caption>

	2002	2001	2000

<S>	<C>	<C>	<C>
Risk free interest rate	3.7%	4.5%	6.3%
Expected life (years)	5.0	5.0	5.0
Expected volatility	61.0%	43.9%	52.1%
Expected dividends	--	--	--

</Table>

11. EQUITY TRANSACTIONS

In November 1995, the Company sold 1,315,500 shares of $2.125 Convertible Exchangeable Preferred Stock, Series A (the "Preferred Stock") for net proceeds of $30.9 million. Annual dividends are $2.125 per share and are cumulative. The net proceeds of the $.01 par value stock after underwriters discount and expense was $30,899,000. Each share has a liquidation preference of $25.00, plus accrued and unpaid dividends. Dividends on the Preferred Stock are cumulative from the date of issuance and are payable quarterly, commencing January 15, 1996. The Preferred Stock is convertible at any time, at the option of

the holders thereof, unless previously redeemed, into shares of Common Stock of the Company at an initial conversion price of $11 per share of Common Stock, subject to adjustments under certain conditions.

The Preferred Stock is redeemable at any time on or after December 31, 1998, in whole or in part at the option of the Company at a redemption price of $26.488 per share beginning at December 31, 1998 and at premiums declining to the $25.00 liquidation preference by the year 2005 and thereafter, plus accrued and unpaid dividends. The Preferred Stock is also exchangeable, in whole, but not in part, at the option of the Company on or after January 15, 1998 for the Company's 8.5% Convertible Subordinated Debentures due 2010 (the "Debentures") at a rate of $25.00 principal amount of Debentures for each share of Preferred Stock. The Debentures will be convertible into Common Stock of the Company on the same terms as the Preferred Stock and will pay interest semi-annually.

In a December 1998 private transaction, a preferred stockholder elected to convert 59,689 shares of Preferred Stock into 136,867 shares of the Company's Common Stock. In 1999 certain other preferred stockholders, through private transactions, agreed to convert 210,350 shares of Preferred Stock into 502,637 shares of the Company's Common Stock under similar terms. Likewise in 2000, 444,600 shares of Preferred Stock were converted into 1,036,098 shares of the Company's Common Stock. Any non-cash premium negotiated in excess of the conversion rate was recorded as additional preferred stock dividends and excluded from the Consolidated Statements of Cash Flows.

In November of 1999, the Company sold 3,680,000 shares of Common Stock in a public offering at a price to the public of $11.875 per share. Cash proceeds received by the Company were $41.1 million net of underwriting discount and offering costs.

In 2001, under the terms of the $95 million multiple advance loans, the Company issued warrants to purchase, at a nominal exercise price, 265,210 shares of its common stock. See Note 5.

The Company adopted a stockholder rights plan on March 30, 2000, designed to assure that the Company's stockholders receive fair and equal treatment in the event of any proposed takeover of the Company and to guard against partial tender offers, squeeze-outs, open market accumulations, and other abusive tactics to gain control without paying all stockholders a fair price. The rights plan was not adopted in response to any specific takeover proposal. Under the rights plan, the Company declared a dividend of one right ("Right") on each share of the Company's Common Stock. Each Right will entitle the holder to purchase one one-thousandth of a share of a Series B Preferred Stock, par value $0.01 per share, at an exercise price of $90 per one one-thousandth of a share.

The Rights are not currently exercisable and will become exercisable only in the event a person or group acquires, or engages in a tender or exchange offer to acquire, beneficial ownership of 15 percent or more (one existing stockholder was granted an exception for up to 21 percent) of the Company's Common Stock. After the Rights become exercisable, each Right will also entitle its holder to purchase a number of common shares of the Company having a market value of twice the exercise price. The dividend distribution was made to stockholders of record at the close of business on April 10, 2000. The Rights will expire on March 30, 2010.

12. SUPPLEMENTAL OIL AND GAS RESERVE DATA (UNAUDITED)

The Company's proved oil and gas reserves at December 31, 2002, 2001 and 2000 have been estimated by independent petroleum consultants in accordance with guidelines established by the Securities and Exchange Commission ("SEC"). Accordingly, the following reserve estimates are based upon existing economic and operating conditions. These estimates have been adjusted (per SEC guidelines) to exclude the volumetric production payment described in Note 2.

There are numerous uncertainties inherent in establishing quantities of proved reserves. The following reserve data represent estimates only and should not be construed as being exact. In addition, the standard measure of discounted future net cash flows should not be construed as the current market value of the Company's oil and gas properties or the cost that would be incurred to obtain equivalent reserves.

In October 2002, we received a letter from the SEC regarding our Annual Report on Form 10-K for the year ended December 31, 2001 requesting supplemental information concerning our operations in the Gulf of Mexico. The comment letters requested information about the procedures we used to classify our deepwater reserves as proved and requested that our financials be restated to reflect the removal of the Boomslang reserves as proved for all prior periods during which such reserves were reported as proved. We have reviewed the SEC comments with our independent petroleum reserve engineers, Huddleston & Co., Inc. of Houston, Texas. Both Huddleston & Co. and Callon believe that such deepwater reserves are properly classified as proved. If the SEC requires us to retroactively classify Boomslang as an unproved property through December, 2002, we would be required to restate our financial position, results of operations, and supplemental oil and gas reserve data from 1998 through 2002.

ESTIMATED RESERVES

Changes in the estimated net quantities of crude oil and natural gas reserves, all of which are located onshore and offshore in the continental United States, are as follows:

RESERVE QUANTITIES

<Table>
<Caption>

<S>	YEARS ENDED DECEMBER 31, 2002 <C>	2001 <C>	2000 <C>
Proved developed and undeveloped reserves:			
Crude Oil (MBbls):			
Beginning of period	30,209	33,382	23,834
Revisions to previous estimates	(5,951)	(2,290)	85
Purchase of reserves in place	--	--	--
Sales of reserves in place	--	(624)	--
Extensions and discoveries	11	14	9,695
Production	(226)	(273)	(232)
End of period	24,043	30,209	33,382
Natural Gas (MMcf):			
Beginning of period	120,299	129,922	110,621
Revisions to previous estimates	(17,279)	(4,578)	(4,817)

Purchase of reserves in place	--	--	347
Sales of reserves in place	--	(1,296)	--
Extensions and discoveries	1,579	7,483	35,387
Production	(13,060)	(11,232)	(11,616)
End of period	91,539	120,299	129,922
Proved developed reserves:			
Crude Oil (MBbls):			
Beginning of period	885	2,192	1,376
End of period	1,056	885	2,192
Natural Gas (MMcf):			
Beginning of period	51,221	63,982	76,295
End of period	37,631	51,221	63,982

</Table>

STANDARDIZED MEASURE

The following tables present the Company's standardized measure of discounted future net cash flows and changes therein relating to proved oil and gas reserves and were computed using reserve valuations based on regulations prescribed by the SEC. These regulations provide that the oil, condensate and gas price structure utilized to project future net cash flows reflects current prices (approximately $4.80 per Mcf for natural gas and $34.22 per Bbl for oil for the 2002 disclosures, $2.58 per Mcf and $20.10 per Bbl for 2001 disclosures, and $9.14 per Mcf and $26.71 per Bbl for 2000 disclosures) at each date presented and have not been escalated. Future production, development and net abandonment costs are based on current costs

without escalation. The resulting net future cash flows have been discounted to their present values based on a 10% annual discount factor.

STANDARDIZED MEASURE

<Table>
<Caption>

	YEARS ENDED DECEMBER 31,		
	2002	2001	2000
<S>	<C>	<C>	<C>
Future cash inflows	$ 1,261,571	$ 883,145	$ 2,080,680
Future costs -			
Production	(165,559)	(220,857)	(284,667)
Development and net abandonment	(125,813)	(191,369)	(217,507)
Future net inflows before income taxes	970,199	470,919	1,578,506
Future income taxes	(119,020)	(30,315)	(472,637)
Future net cash flows	851,179	440,604	1,105,869
10% discount factor	(295,133)	(185,747)	(434,672)
Standardized measure of discounted future net cash flows	$ 556,046	$ 254,857	$ 671,197

</Table>

CHANGES IN STANDARDIZED MEASURE

<Table>
<Caption>

	YEARS ENDED DECEMBER 31,		
	2002	2001	2000
	(IN THOUSANDS)		
Standardized measure - beginning of period	$ 254,857	$ 671,197	$ 256,322
Sales and transfers, net of production costs	(38,375)	(45,672)	(42,132)
Net change in sales and transfer prices, net of production costs	401,837	(604,391)	361,179
Exchange and sale of in place reserves	--	(5,850)	--
Purchases, extensions, discoveries, and improved recovery, net of future production and development costs incurred	8,456	9,358	276,770
Revisions of quantity estimates	(103,452)	(23,314)	(12,399)
Accretion of discount	26,915	90,978	28,581
Net change in income taxes	(53,608)	224,290	(209,090)
Changes in production rates, timing and other	59,416	(61,739)	11,966
Standardized measure - end of period	$ 556,046	$ 254,857	$ 671,197

</Table>

13. SUMMARIZED QUARTERLY FINANCIAL INFORMATION (UNAUDITED)

<Table>
<Caption>

	FIRST QUARTER	SECOND QUARTER	THIRD QUARTER	FOURTH QUARTER
	(IN THOUSANDS, EXCEPT PER SHARE DATA)			
2002				
Total revenues	$ 11,624	$ 20,489	$ 15,786	$ 19,209
Total costs and expenses	15,399	16,888	17,786	19,606
Income tax expense (benefit)	(1,321)	1,260	(700)	(139)
Net income (loss)	(2,454)	2,341	(1,300)	(258)
Net income per share-basic	(0.21)	0.15	(0.12)	(0.04)
Net income per share-diluted	(0.21)	0.15	(0.12)	(0.04)
2001				
Total revenues	$ 20,812	$ 17,712	$ 12,715	$ 10,513
Total costs and expenses	11,314	12,398	12,311	22,936
Income tax expense (benefit)	3,324	1,860	142	(4,349)
Net income	6,174	3,454	262	(8,074)
Net income per share-basic	0.44	0.24	0.00	(0.63)
Net income per share-diluted	0.41	0.23	0.00	(0.63)

</Table>

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

As reported in our Current Report on Form 8-K dated June 28, 2002, in June 2002, the Board of Directors of the company approved the engagement of Ernst & Young LLP as its independent auditors for the fiscal year ending December 31, 2002 to replace Arthur Andersen LLP, who were dismissed as auditors of the company effective June 28, 2002. The audit committee of the Board of Directors approved the change in auditors and recommended this change to the Board of Directors. The letter of concurrence was filed as an exhibit to the Form 8-K. No disagreements were cited.

There have been no disagreements with the independent auditors on any matters of accounting principles or practices, financial statement disclosure, or auditing scope or procedures.

PART III.

ITEM 10. DIRECTORS AND EXECUTIVE OFFICERS OF THE REGISTRANT.

For information concerning Item 10, see the definitive proxy statement of Callon Petroleum Company relating to the Annual Meeting of Stockholders on May 2, 2003 which will be filed with the Securities and Exchange Commission and is incorporated herein by reference.

ITEM 11. EXECUTIVE COMPENSATION.

For information concerning Item 11, see the definitive proxy statement of Callon Petroleum Company relating to the Annual Meeting of Stockholders on May 2, 2003 which will be filed with the Securities and Exchange Commission and is incorporated herein by reference.

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

For information concerning the security ownership of certain beneficial owners and management, see the definitive proxy statement of Callon Petroleum Company relating to the Annual Meeting of Stockholders on May 2, 2003 which will be filed with the Securities and Exchange Commission and is incorporated herein by reference.

EQUITY COMPENSATION PLAN INFORMATION

The following table provides information as of December 31, 2002 regarding the number of shares of Common Stock that may be issued under the Company's equity compensation plans.

<Table>
<Caption>

Plan Category	Number of securities to be issued upon exercise of outstanding options, warrants and rights (a)	Weighted-average exercise price of outstanding options, warrants and rights (b)	Number of securities remaining available for future issuance under equity compensation plans (excluding securities reflected in column (a) (c)
<S>	<C>	<C>	<C>
Equity compensation plans approved by security holders(1)	2,351,667	$ 10.31	186,493
Equity compensation plans not approved by security holders (2)	168,750	$ 4.16	181,250
Total	2,520,417	$ 9.90	367,743

</Table>

(1) Represents the Callon Petroleum Company 1994 and the 1996 Stock Incentive Plans which were approved by the shareholders in prior years. Remaining shares available for future issuance listed in column (c) does not include 168,000 shares of restricted stock awarded in 2002 which have not yet vested.

(2) Represents the Callon Petroleum Company 2002 Stock Incentive Plan adopted by the Company on February 14, 2002. The plan qualifies as a "broadly based" plan under the provisions of the New York Stock Exchange rules and regulations and therefore did not require shareholder approval. Remaining shares available for future issuance listed in column (c) does not include 124,300 shares of restricted stock awarded in 2002 which have not yet vested.

See Note 10 to the Consolidated Financial Statements for a description of the material provisions of each equity compensation plan under which our equity securities are authorized for issuance that was adopted without the approval of shareholders.

ITEM 13. CERTAIN RELATIONSHIPS AND RELATED TRANSACTIONS

For information concerning Item 13, see the definitive proxy statement of Callon Petroleum Company relating to the Annual Meeting of Stockholders on May 2, 2003 which will be filed with the Securities and Exchange Commission and is incorporated herein by reference.

ITEM 14. CONTROLS AND PROCEDURES.

(a) Evaluation of Disclosure Controls and Procedures. Based on their evaluation as of a date within 90 days of the filing date of this Annual Report on Form 10-K, the Company's principal executive officer and principal financial officer have concluded that the Company's disclosure controls and procedures (as defined in Rules 13a-14(c) and 15d-14(c) under the Securities Exchange Act of 1934 (the "Exchange Act") are effective to ensure that information required to be disclosed by the Company in reports that it files or submits under the Exchange Act is recorded, processed, summarized and reported within the time periods specified in the rules and forms of the Securities and Exchange Commission.

(b) Changes in Internal Controls. There were no significant changes in the Company's internal controls or in other factors that could significantly affect these controls subsequent to the date of their evaluation, including any corrective actions with regard to significant deficiencies and material weaknesses.

PART IV.

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

(a) 1. The following is an index to the financial statements and financial statement schedules that are filed as part of this Form 10-K on pages 37 through 63.

Report of Independent Auditors

Consolidated Balance Sheets as of the Years Ended December 31, 2002 and 2001

Consolidated Statements of Operations for the Three Years in the Period Ended December 31, 2002

Consolidated Statements of Stockholders' Equity for the Three Years in the Period Ended December 31, 2002

Consolidated Statements of Cash Flows for the Three Years in the Period Ended December 31, 2002

Notes to Consolidated Financial Statements

(a) 2. Schedules other than those listed above are omitted because they are not required, not applicable or the required information is included in the financial statements or notes thereto.

(a) 3. Exhibits:

2. Plan of acquisition, reorganization, arrangement, liquidation or succession*

3. Articles of Incorporation and Bylaws

3.1 Certificate of Incorporation of the Company, as amended (incorporated by reference from Exhibit 3.1 of the Company's Registration Statement on Form S-4, filed August 4, 1994, Reg. No. 33-82408)

3.2 Certificate of Merger of Callon Consolidated Partners, L. P. with and into the Company dated September 16, 1994 (incorporated by reference from Exhibit 3.2 of the Company's Report on Form 10-K for the fiscal year ended December 31, 1994, File No. 000-25192)

3.3 Bylaws of the Company (incorporated by reference from Exhibit 3.2 of the Company's Registration Statement on Form S-4, filed August 4, 1994, Reg. No. 33-82408)

4. Instruments defining the rights of security holders, including indentures

4.1 Specimen Common Stock Certificate (incorporated by reference from Exhibit 4.1 of the Company's Registration Statement on Form S-4, filed August 4, 1994, Reg. No. 33-82408)

4.2 Specimen Preferred Stock Certificate (incorporated by reference from Exhibit 4.2 of the Company's Registration Statement on Form S-1, filed November 13, 1995, Reg. No. 33-96700)

4.3 Designation for Convertible, Exchangeable Preferred Stock, Series A (incorporated by reference from Exhibit 4.3 of the Company's Registration Statement on Form S-1, filed November 13, 1995, Reg. No. 33-96700)

4.4 Indenture for Convertible Debentures (incorporated by reference from Exhibit 4.4 of the Company's Registration Statement on Form S-1, filed November 13, 1995, Reg. No. 33-96700)

4.5 Certificate of Correction on Designation of Series A Preferred Stock (incorporated by reference from Exhibit 4.4 of the Company's Registration Statement on Form S-1, filed November 22, 1996, Reg. No. 333-15501)

4.6 Indenture for the Company's 10.125% Senior Subordinated Notes due 2002 dated as of July 31, 1997 (incorporated by reference from

Exhibit 4.1 of the Company's Registration Statement on Form S-4, filed September 25, 1997, Reg. No. 333-36395)

4.7 Form of Note Indenture for the Company's 10.25% Senior Subordinated Notes due 2004 (incorporated by reference from Exhibit 4.10 of the Company's Registration Statement on Form S-2, filed June 14, 1999, Reg. No. 333-80579)

4.8 Rights Agreement between Callon Petroleum Company and American Stock Transfer & Trust Company, Rights Agent, dated March 30, 2000 (incorporated by reference from Exhibit 99.1 of the Company's Registration Statement on Form 8-A, filed April 6, 2000, File No. 001-14039)

4.9 Subordinated Indenture for the Company dated October 26, 2000 (incorporated by reference from Exhibit 4.1 of the Company's Current Report on Form 8-K dated October 24, 2000, File No. 001-14039)

4.10 Supplemental Indenture for the Company's 11% Senior Subordinated Notes due 2005 (incorporated by reference from Exhibit 4.2 of the Company's Current Report on Form 8-K dated October 24, 2000, File No. 001-14039)

4.11 Warrant dated as of June 29, 2001 entitling Duke Capital Partners, LLC to purchase common stock from the Company. (incorporated by reference to Exhibit 4.11 of the Company's Quarterly Report on Form 10-Q for the period ended June 30, 2001, File No. 001-14039)

4.12 First Supplemental Indenture, dated June 26, 2002, to Indenture between Callon Petroleum Company and American Stock Transfer & Trust Company dated July 31, 1997. (incorporated by reference to Exhibit 4.1 of the Company's Current Report on Form 8-K dated June 26, 2002, File No. 001-14039)

4.13 Form of Warrant entitling certain holders of the Company's 10.125% Senior Subordinated Notes due 2002 to purchase common stock from the Company (incorporated by reference to

Exhibit 4.13 of the Company's Form 10-Q for the period ended June 30, 2002, File No. 001- 14039)

4.14 Second Supplemental Indenture, dated September 16, 2002, to Indenture between Callon Petroleum Company and American Stock Transfer & Trust Company dated July 31, 1997. (incorporated by reference to Exhibit 4.1 of the Company's Current Report on Form 8-K dated September 16, 2002, File No. 001-14039)

9. Voting trust agreement

None.

10. Material contracts

10.1 Registration Rights Agreement dated September 16, 1994 between the Company and NOCO Enterprises, L. P. (incorporated by reference from Exhibit 10.2 of the Company's Registration Statement on Form 8-B filed October 3, 1994)

10.2 Counterpart to Registration Rights Agreement by and between the Company, Ganger Rolf ASA and Bonheur ASA. (incorporated by reference from Exhibit 10.2 of the Company's Report on Form 10-K for the fiscal year ended December 31, 2000, File No. 001-14039)

10.3 Registration Rights Agreement dated September 16, 1994 between the Company and Callon Stockholders (incorporated by reference from Exhibit 10.3 of the Company's Registration Statement on Form 8-B filed October 3, 1994)

10.4 Callon Petroleum Company 1994 Stock Incentive Plan (incorporated by reference from Exhibit 10.5 of the Company's Registration Statement on Form 8-B filed October 3, 1994)

10.5 Consulting Agreement between the Company and John S. Callon dated June 19, 1996 (incorporated by reference from Exhibit 10.10 of the Company's Registration Statement on Form S-1, filed November 5, 1996, Reg. No. 333-15501)

10.6 Callon Petroleum Company Amended 1996 Stock Incentive Plan (incorporated by reference from Exhibit 4.4 of the Post-Effective Amendment No. 1 to the Company's Registration Statement on Form S-8, filed February 5, 1999, Reg No. 333-29537)

10.7 Purchase and Sale Agreement between Callon Petroleum Operating Company and Murphy Exploration Company, dated May 26, 1999 (incorporated by reference from Exhibit 10.11 on Form S-2, filed June 14, 1999, Reg. No. 333-80579)

10.8 Callon Petroleum Company 1996 Stock Incentive Plan as amended on May 9, 2000 (incorporated by reference from Appendix I of the Company's Definitive Proxy Statement of Schedule 14A filed March 28, 2000)

10.9 Credit Agreement dated as of October 30, 2000 between the Company and First Union National Bank, as administrative agent for the lenders (incorporated by reference from Exhibit 10.2 of the Company's Quarterly Report on Form 10-Q for the period ended September 30, 2000, File No. 001-14039)

10.10 Credit Agreement dated as of June 29, 2001 between the Company and Duke Capital Partners, LLC, as Administrative Agent (incorporated by reference to Exhibit 10.01 of the Company's Quarterly Report on Form 10-Q for the period ended June 30, 2001, File No. 001-14039)

10.11 Second Amendment to Credit Agreement by and among the Company and First Union National Bank, as Administrative Agent, effective as of June 29, 2001 (incorporated by reference to Exhibit 10.01 of the Company's Quarterly Report on Form 10-Q for the period ended June 30, 2001, File No. 001-14039)

10.12 Conveyance of Overriding Royalty Interest from the Company to Duke Capital Partners, LLC, dated June 29, 2001 (incorporated by reference to Exhibit 10.03 of the Company's Quarterly Report on Form 10-Q for the period ended June 30, 2001, File No. 001-14039)

10.13 Callon Petroleum Company 2002 Stock Incentive Plan (incorporated by reference to Exhibit 10.13 of the Company's Annual Report on Form 10-K for the year ended December 31, 2001, File No. 001-14039).

10.14 Change of Control Severance Compensation Agreement by and between Callon Petroleum and John S. Weatherly dated January 1, 2002 (incorporated by reference to Exhibit 10.14 of the Company's Annual Report on Form 10-K for the year ended December 31, 2001, File No. 001-14039)

10.15 Change of Control Severance Compensation Agreement by and between Callon Petroleum Company and Fred L. Callon, dated January 1, 2002 (incorporated by reference to Exhibit 10.15 of the Company's Annual Report on Form 10-K for the year ended December 31, 2001, File No. 001-14039)

10.16 Change of Control Severance Compensation Agreement by and between Callon Petroleum Company and Dennis W. Christian, dated January 1, 2002 (incorporated by reference to Exhibit 10.16 of the Company's Annual Report on Form 10-K for the year ended December 31, 2001, File No. 001-14039)

10.17 First Amended and Restated Credit Agreement dated as of June 30, 2002, among Callon Petroleum Company, each of the lenders that is a signatory thereto, Wachovia Bank National Association, as administrative agent, and Union Bank of California, N.A., as documentation agent (incorporated by reference to Exhibit 10.1 of the Company's Form 10-Q for the period ended June 30, 2002, File No. 001-14039)

11. Statement re computation of per share earnings*

12. Statements re computation of ratios*

13. Annual Report to security holders, Form 10-Q or quarterly reports*

16. Letter re change in certifying accountant*

18. Letter re change in accounting principles*

21. Subsidiaries of the Company

21.1 Subsidiaries of the Company (incorporated by reference from Exhibit 21.1 of the Company's Registration Statement on Form 8-B filed October 3, 1994)

22. Published report regarding matters submitted to vote of security holders*

23. Consents of experts and counsel

23.1 Consent of Ernst & Young LLP

24. Power of attorney*

99. Additional Exhibits

99.1 Certification of Chief Executive Officer pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002

99.2 Certification of Chief Financial Officer pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002

- ----------------------------
*Inapplicable to this filing.

(b) Reports on Form 8-K.

Current Report dated June 26, 2002, reporting Item 5. Other Events

Current Report dated June 28, 2002, reporting Item 4. Change in Registrant's Certifying Accounts

Current Report dated August 14, 2002, reporting Item 9. Regulation FD Disclosure

Current Report dated September 16, 2002, reporting Item 5. Other Events

Current Report dated October 1, 2002, reporting Item 9. Regulation FD Disclosure

Current Report dated December 12, 2002, reporting Item 9. Regulation FD Disclosure

SIGNATURES

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

CALLON PETROLEUM COMPANY

Date: March 27, 2003	/s/ Fred L. Callon Fred L. Callon (principal executive officer, director)
Date: March 27, 2003	/s/ John S. Weatherly John S. Weatherly (principal financial officer)
Date: March 27, 2003	/s/ James O. Bassi James O. Bassi (principal accounting officer)
Date: March 27, 2003	/s/John S. Callon John S. Callon (director)
Date: March 27, 2003	/s/Dennis W. Christian Dennis W. Christian (director)
Date: March 27, 2003	/s/B. F. Weatherly B. F. Weatherly (director)
Date: March 27, 2003	/s/Robert A. Stanger Robert A. Stanger (director)

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

	CALLON PETROLEUM COMPANY
Date: March 27, 2003	By: /s/ John S. Weatherly John S. Weatherly, Senior Vice President and Chief Financial Officer

CERTIFICATIONS

I, Fred L. Callon, certify that:

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

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

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

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

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

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

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

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

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

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

6. The registrant's other certifying officers and I have indicated in this annual report whether or not there were significant changes in internal controls or in other factors that could significantly affect internal controls subsequent to the date of our most recent evaluation, including any corrective actions with regard to significant deficiencies and material weaknesses.

Date: March 27, 2003
By: /s/ Fred L. Callon

Fred L. Callon, President and Chief Executive Officer
(Principal Executive Officer)

CERTIFICATIONS

I, John S. Weatherly, certify that:

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

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

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

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

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

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

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

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

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

6. The registrant's other certifying officers and I have indicated in this annual report whether or not there were significant changes in internal controls or in other factors that could significantly affect internal controls subsequent to the date of our most recent evaluation, including any corrective actions with regard to significant deficiencies and material weaknesses.

Date: March 27, 2003
By: /s/ John S. Weatherly

John S. Weatherly, Senior Vice President
and Chief Financial Officer (Principal Financial Officer)

EXHIBIT INDEX

2. Plan of acquisition, reorganization, arrangement, liquidation or succession*

3. Articles of Incorporation and Bylaws

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4.8 Rights Agreement between Callon Petroleum Company and American Stock Transfer & Trust Company, Rights Agent, dated March 30, 2000 (incorporated by reference from Exhibit 99.1 of the Company's Registration Statement on Form 8-A, filed April 6, 2000, File No. 001-14039)

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10.8 Callon Petroleum Company 1996 Stock Incentive Plan as amended on May 9, 2000 (incorporated by reference from Appendix I of the Company's Definitive Proxy Statement of Schedule 14A filed March 28, 2000)

10.9 Credit Agreement dated as of October 30, 2000 between the Company and First Union National Bank, as administrative agent for the lenders (incorporated by reference from Exhibit 10.2 of the Company's Quarterly Report on Form 10-Q for the period ended September 30, 2000, File No. 001-14039)

10.10 Credit Agreement dated as of June 29, 2001 between the Company and Duke Capital Partners, LLC, as Administrative Agent (incorporated by reference to Exhibit 10.01 of the Company's Quarterly Report on Form 10-Q for the period ended June 30, 2001, File No. 001-14039)

10.11 Second Amendment to Credit Agreement by and among the Company and First Union National Bank, as Administrative Agent, effective as of June 29, 2001 (incorporated by reference to Exhibit 10.01 of the Company's Quarterly Report on Form 10-Q for the period ended June 30, 2001, File No. 001-14039)

10.12 Conveyance of Overriding Royalty Interest from the Company to Duke Capital Partners, LLC, dated June 29, 2001 (incorporated by reference to Exhibit 10.03 of the Company's Quarterly Report on Form 10-Q for the period ended June 30, 2001, File No. 001-14039)

10.13 Callon Petroleum Company 2002 Stock Incentive Plan (incorporated by reference to Exhibit 10.13 of the Company's Annual Report on Form 10-K for the year ended December 31, 2001, File No. 001-14039).

10.14 Change of Control Severance Compensation Agreement by and between Callon Petroleum and John S. Weatherly dated January 1, 2002 (incorporated by reference to Exhibit 10.14 of the Company's Annual Report on Form 10-K for the year ended December 31, 2001, File No. 001-14039)

10.15 Change of Control Severance Compensation Agreement by and between Callon Petroleum Company and Fred L. Callon, dated January 1, 2002 (incorporated by reference to Exhibit 10.15 of the Company's Annual Report on Form 10-K for the year ended December 31, 2001, File No. 001-14039)

10.16 Change of Control Severance Compensation Agreement by and between Callon Petroleum Company and Dennis W. Christian, dated January 1, 2002 (incorporated by reference to Exhibit 10.16 of the Company's Annual Report on Form 10-K for the year ended December 31, 2001, File No. 001-14039)

10.17 First Amended and Restated Credit Agreement dated as of June 30, 2002, among Callon Petroleum Company, each of the lenders that is a signatory thereto, Wachovia Bank National Association, as administrative agent, and Union Bank of California, N.A., as documentation agent (incorporated by reference to Exhibit 10.1 of the Company's Form 10-Q for the period ended June 30, 2002, File No. 001-14039)

11. Statement re computation of per share earnings*

12. Statements re computation of ratios*

13. Annual Report to security holders, Form 10-Q or quarterly reports*

16. Letter re change in certifying accountant*

18. Letter re change in accounting principles*

21. Subsidiaries of the Company

21.1 Subsidiaries of the Company (incorporated by reference from Exhibit 21.1 of the Company's Registration Statement on Form 8-B filed October 3, 1994)

22. Published report regarding matters submitted to vote of security holders*

23. Consents of experts and counsel

23.1 Consent of Ernst & Young LLP

24. Power of attorney*

99. Additional Exhibits

99.1 Certification of Chief Executive Officer pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002

99.2 Certification of Chief Financial Officer pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002

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*Inapplicable to this filing.

EXHIBIT 23.1

CONSENT OF INDEPENDENT AUDITORS

We consent to the incorporation by reference in the Registration Statements (File Nos. 333-100646, 333-87945, 333-60606, 333-47784, 333-29537, 333-29529, and 333-90410) of Callon Petroleum Company of our report dated February 28, 2003, with respect to the 2002 consolidated financial statements of Callon Petroleum Company included in this Form 10-K for the year ended December 31, 2002.

Ernst & Young LLP

New Orleans, Louisiana
March 27, 2003

EXHIBIT 99.1

CERTIFICATION PURSUANT TO
18 U.S.C. SECTION 1350,
AS ADOPTED PURSUANT TO
SECTION 906 OF THE SARBANES-OXLEY ACT OF 2002

In connection with the Annual Report of Callon Petroleum Company (the "COMPANY") on Form 10-K for the fiscal year ended December 31, 2002, as filed with the Securities and Exchange Commission on the date hereof (the "REPORT"), I, Fred L. Callon, Chief Executive Officer of the Company, certify, pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, that to my knowledge:

(1) The Report fully complies with the requirements of Section 13(a) or 15(d) of the Securities and Exchange Act of 1934, as amended; and

(2) The information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Company.

Dated: March 27, 2003

/s/ Fred L. Callon

Fred L. Callon, Chief Executive Officer

A signed original of this written statement required by Section 906 has been provided to Callon Petroleum Company and will be retained by Callon Petroleum Company and furnished to the Securities and Exchange Commission or its staff upon request.

EXHIBIT 99.2

CERTIFICATION PURSUANT TO
18 U.S.C. SECTION 1350,
AS ADOPTED PURSUANT TO
SECTION 906 OF THE SARBANES-OXLEY ACT OF 2002

In connection with the Annual Report of Callon Petroleum Company (the "COMPANY") on Form 10-K for the fiscal year ended December 31, 2002, as filed with the Securities and Exchange Commission on the date hereof (the "REPORT"), I, John S. Weatherly, Chief Financial Officer of the Company, certify, pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, that to my knowledge:

(1) The Report fully complies with the requirements of Section 13(a) or 15(d) of the Securities and Exchange Act of 1934, as amended; and

(2) The information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Company.

Dated: March 27, 2003

/s/ John S. Weatherly

John S. Weatherly, Chief Financial Officer

A signed original of this written statement required by Section 906 has been provided to Callon Petroleum Company and will be retained by Callon Petroleum Company and furnished to the Securities and Exchange Commission or its staff upon request.