CALLON PETROLEUM CO
Form 10-K405
April 01, 2002

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, 2001

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]

The aggregate market value of the voting stock held by nonaffiliates of the registrant was approximately $98,778,082 as of March 18, 2002 (based on the last reported sale price of such stock on the New York Stock Exchange).

As of March 18, 2002, there were 13,424,216 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, 2001) relating to the Annual Meeting of Stockholders to be held on May 8, 2002, which is incorporated into Part III of this Form 10-K.

PART I.

ITEM 1. BUSINESS

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 formed 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 several 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. Over the last several years we have expanded our areas of exploration to include the Gulf of Mexico Deepwater area (generally 900 to 5,500 feet of water).

We ended the year 2001 with estimated net proved reserves of 303 billion cubic feet of natural gas equivalent ("Bcfe"). This represents a decrease of 9% from 2000 year-end estimated net proved reserves of 334 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.

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 $112.6 million in 2001. We incurred approximately $63.7 million in the Gulf of Mexico Shelf area.

The Gulf of Mexico Deepwater area expenditures ($31.9 million) accounted for the remainder of the total capital expended, along with $4.2 million incurred in leasehold and seismic acquisition costs and $12.8 million of interest and general and administrative costs allocable directly to exploration and development projects. The Gulf of Mexico Deepwater area expenditures included one unsuccessful exploration project totaling $2.2 million and the balance was incurred for additional delineation drilling and production facility fabrication at our Medusa discovery and the delineation drilling at Habanero.

As a result of recent 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 2002 and beyond. We are currently evaluating various financing alternatives to address these issues. While management believes there are a number of financing sources available to us, no assurances can be made that we will be able to fund these development costs.

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, 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 Coast 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 2001, 44% of our daily production came from two of our properties in the Gulf of Mexico. Moreover, one property accounted for 25% 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, 2001 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 five discoveries 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:

- unexpected drilling conditions;
- pressure or inequalities in formations;
- equipment failures or accidents;
- adverse weather conditions;

- compliance with governmental requirements; and
- shortages or delays in the availability of drilling rigs and the delivery of equipment.

BECAUSE WE DO NOT CONTROL ALL OF OUR PROPERTIES, ESPECIALLY OUR DEEPWATER PROPERTIES, WE HAVE LIMITED INFLUENCE OVER THEIR DEVELOPMENT. We do not operate all of our properties and have limited influence over the operations of some of these properties, particularly our deepwater projects. Our lack of control could result in the following:

- the operator may initiate exploration or development on a faster or slower pace than we prefer;
- 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
- 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. They require the application of more advanced drilling technologies, involving a higher risk of technological failure and usually resulting in significantly higher drilling costs. Deepwater wells are completed using subsea 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:

- decisions made by the operators of our deepwater wells;
- the availability of materials necessary to construct the facilities;
- the proximity of our discoveries to pipelines; and
- 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, 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 prospectus.

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 prospectus. 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 prospectus 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, 2001, approximately 77.3% of the discounted present value of our estimated net proved reserves were proved undeveloped. 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.

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 capsizings, 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 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
- 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. In late 2000, we opened a field office in Houston, Texas, staffed with recently hired technical professionals, to enhance exploration and development efforts. 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 103 employees as of December 31, 2001, 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 eight 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, installation and operation of 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 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 policies thereunder, 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, installation and operation of 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 owns or leases numerous properties that have been used for production of oil and gas for many years. Although the Company has utilized operating and disposal practices standard in the industry at the time, hydrocarbons or other solid wastes may have been disposed or released on or under these properties. In addition, many of these properties have been operated by third parties. The Company had 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 these new laws, the Company could be required to remove or remediate 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 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 EPA has limited the disposal

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options for certain hazardous wastes and is considering the adoption of stricter disposal standards for nonhazardous wastes. Furthermore, it is possible that certain wastes currently exempt from treatment as "hazardous wastes" generated by the Company's oil and gas operations 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 Comprehensive Environmental Response, Compensation and Liability Act ("CERCLA"), also known as the "Superfund" law, imposes liability, without regard to fault or the legality of the original conduct, on certain classes of persons with respect to the release of a "hazardous substance" into the environment. These persons include the owner and operator of a site and persons that disposed or arranged for the disposal of the 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 responsible classes of persons the costs of such action. Neither the Company nor its predecessors has been designated as a potentially responsible party by the EPA under CERCLA with respect to any such site.

OIL POLLUTION ACT. The Oil Pollution Act of 1990 (the "OPA") and regulations thereunder impose a variety of regulations on "responsible parties" related to the prevention of oil spills and liability for damages resulting from such spills in United States waters. A "responsible party" includes the owner or operator of a facility or vessel, or the lessee or permittee of the area in which an offshore facility is located. The OPA assigns liability to each responsible party for oil removal costs and a variety of public and private damages. While liability limits apply in some circumstances, a party cannot take advantage of liability limits if the spill was caused by gross negligence or willful misconduct or resulted from violation of a federal safety, construction or operating regulation. If the party fails to report a spill or to cooperate fully in the cleanup, liability limits likewise do not apply. Few defenses exist to the liability imposed by the OPA.

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 OCS waters, with higher amounts, up to $150 million based upon worst case oil-spill discharge volume calculations. The Company believes that it currently has established adequate proof of financial responsibility for its offshore facilities.

AIR EMISSIONS. The operations of the Company are subject to local, state and federal regulations for the control of emissions from sources of air pollution. Administrative enforcement actions for failure to comply strictly with air regulations or permits are generally resolved by payment of monetary fines and correction of any identified deficiencies. Alternatively, regulatory agencies could require the Company to forego construction or operation of certain air emission sources, although the Company believes that in such case it would have enough permitted or permittable capacity to continue its operations without a material adverse effect on any particular producing field.

OSHA. 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 the Federal Superfund Amendment and Reauthorization Act and similar state statutes require the Company to organize and/or disclose information about hazardous materials used or produced in its operations. Certain of this information must be provided to employees, state and local governmental authorities and local citizens.

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.

ITEM 2. PROPERTIES

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, 2001, our estimated net proved reserves totaled 30.2 million barrels of oil ("MBbl") and 121.5 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 $272.1 million. Gas constitutes approximately 40% of our total estimated proved reserves and approximately 17% of our reserves are proved producing reserves.

SIGNIFICANT PROPERTIES

The following table shows discounted cash flows and estimated net proved oil and gas reserves by major field, within focus area, for our nine largest fields and for all other properties combined at December 31, 2001.

		ESTIMATED NET PROVED RESERVES			PR
	OPERATOR	OIL (MBBLS)	GAS (MMCF) (b)	TOTAL (MMCFE) (b)	
GULF OF MEXICO SHELF:					
Mobile Block 864 Area	Callon	--	41,054	41,054	
Main Pass Block 26 SL 15827	Callon	40	915	1,152	
East Cameron Block 294	Unocal	14	2,860	2,945	
High Island Block A-494 "Snapper"	PetroQuest	--	4,614	4,614	
GULF OF MEXICO DEEPWATER:					
Garden Banks Blocks 738/782/826/827 "Entrada"	BP Amoco	7,823	29,341	76,279	
Mississippi Canyon 538/582 "Medusa"	Murphy	9,507	9,374	66,415	
Garden Banks Block 341 "Habanero"	Shell	4,736	12,270	40,685	

Ewing Bank Block 994 "Boomslang"	Murphy	7,244	13,040	56,505
ONSHORE AND OTHER:				
Big Escambia Creek	Exxon	412	1,027	3,500
Other	Various	433	6,958	9,557
TOTAL PROVED RESERVES		30,209	121,453	302,706

(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, 2001, as set forth in the Company's reserve reports prepared by its independent petroleum reserve engineers, Huddleston & Co., Inc. of Houston, Texas.

(b) The estimates include reserve volumes of approximately 1.2 Bcf with a pre-tax discounted present value of $2.9 million that are dedicated to a volumetric production payment.

GULF OF MEXICO DEEPWATER

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.

Information obtained in a data swap with another exploration company that has announced a similar discovery adjacent to Entrada, is being incorporated into the Entrada development plans. The owners of the 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.

Medusa, Mississippi Canyon Block 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 British-Borneo Petroleum, Inc. owns the remaining 25%.

In 2001 a delineation program began which included four development wells and one sidetrack. These will provide the take points for initial production. 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. Construction of the facility is in progress. Upon completion, it is estimated the production facility will have the capacity to handle 40,000 barrels of crude oil and 110 million cubic feet of natural gas per day. First production is anticipated in late 2002 or early 2003.

Habanero, Garden Banks Block 341

During February 1999 the initial test well on our Habanero prospect encountered over 200 feet of net pay. 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.

A field delineation program began in midyear 2001, which included sidetracking the existing well with three sidetracks. Development plans include sub-sea completion and tie back to an existing production facility in the area. The operator has submitted to the co-owners a development schedule with estimated initial production in November 2003.

Boomslang, Ewing Bank Block 994

Located in 900 feet of water, the Boomslang prospect was drilled to a total depth of 12,955 feet and encountered 185 net feet of oil pay in three separate zones. In December 1999, we purchased from Santos

USA Corporation an additional 20% working interest in the Boomslang deepwater discovery on Ewing Bank Block 994 for $7.3 million. This brought our total working interest in the well to 55%.

A complete field study was initiated in 2001, which resulted in a delineation and development plan that is scheduled to commence by the second half of 2003. Plans include a sub-sea completion with a tieback to an existing shelf production facility. Plans could be altered if the Sidewinder prospect, located immediately to the southeast of Boomslang on Ewing Bank Block 995 and Green Canyon Blocks 24 and 25, is drilled and results in a discovery. This could result in the need for a stand-alone production facility to serve both Boomslang and Sidewinder. We own a 15% working interest in the Ewing Bank Block 995 and Green Canyon Blocks 24 and 25 leases.

GULF OF MEXICO SHELF

Mobile Block 864 Area

The Mobile Block 864 Area is located offshore Alabama in the federal waters of the Outer Continental Shelf area. We consummated five acquisitions in this area for a total of $63.8 million. In total, we acquired an average 81.6% working interest in seven blocks, a 66.4% working interest in the Mobile Block 864 Area unit and the unit production facilities, and a 100% working interest in three producing wells. We have been appointed operator of the Mobile Block 864 unit and three other wells. Net average daily production during 2001 was 18 MMcf per day.

During the first quarter of 2001, we drilled the Mobile Block 908 #4, an exploratory well, and the Mobile Block 864 A-3, a development well, in our

Mobile Block 864 area, both of which were successful. During the fourth quarter of 2000, the Company performed acid stimulation on three wells. The 908 #4 well commenced production during February 2001 and the A-3 well commenced production during March 2001. These projects increased production in this area during 2001.

In the fourth quarter of 2001, we initiated a production acceleration program for Mobile Blocks 952, 953 and 955, which currently produce through the Mobile Block 864 unit facilities. Plans include at least one acceleration well, which was successfully drilled in the fourth quarter of 2001, stand-alone production facilities and the rerouting of production flow lines. The project is scheduled to be completed late in the first quarter or early second quarter 2002.

East Cameron Block 294

In the first quarter of 2001, this prospect was drilled at a water depth of 186 feet and encountered approximately 80 feet of pay in two intervals at approximately 3,500 and 4,200 feet. First production commenced in the first quarter of 2002 at a net average daily rate of 6 MMcf. We own a 50% working interest in this well and Unocal, the operator, owns the remaining interest.

Main Pass 26 / SL 15827 #1

We negotiated a farm-in agreement in 1998 for a 97% working interest after identifying a prospect on Main Pass Block 26 based upon a seismic survey we completed in 1996. In August 1998, we drilled the SL 15827 well to a depth of 10,450 feet. This well produced during 2001 at a net average daily rate of 2 MMcf of gas and 85 Bbls of oil. We operate this property.

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Snapper, High Island Block A-494

In January 1999, we announced a discovery on our Snapper prospect, which was drilled to a total depth of 8,800 feet. In the second half of 2001, the well was sidetracked and a second well was drilled to test the same zone in an adjacent fault block. The second well had over 100 feet of pay which is fault separated from the initial well with no apparent water. We own a 50% working interest in these wells, which are operated by PetroQuest Energy. The wells began production in the third quarter of 2001, and averaged 7 net MMcf per day for December 2001.

ONSHORE

We own various small royalty and working interests in several onshore areas, which as of December 31, 2001 had total net proved reserves of 9.4 Bcfe with a discounted present value of $5.0 million. Over 50% of these reserves and their related discounted present value were attributable to our interest in the Big Escambia Creek gas field located in south Alabama and operated by Exxon/Mobil.

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,		
	2001(a)	2000(a)	1999(a)

		(IN THOUSANDS)	
Proved developed:			
Oil (Bbls)	885	2,192	1,376
Gas (Mcf)	52,375	67,463	82,109
Proved undeveloped:			
Oil (Bbls)	29,324	31,190	22,458
Gas (Mcf)	69,078	65,940	34,326
Total proved:			
Oil (Bbls)	30,209	33,382	23,834
Gas (Mcf)	121,453	133,403	116,435
Estimated pre-tax future net cash flows	$ 473,896	$1,610,320	$ 528,659
Pre-tax discounted present value	$ 272,053	$ 939,325	$ 296,513
Standardized measure of discounted future net cash flows	$ 254,857	$ 671,197	$ 256,322

(a) The estimates include reserve volumes of approximately 5.8 Bcf, $12.1 million of pre-tax future net cash flows and $10.7 million of pre-tax discounted present value in 1999, 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, and 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.

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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, and 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 are 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.

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 including federal and state waters in the Gulf of Mexico.

	YEARS ENDED DECEMBER 31,					
	2001		2000		1999	
	GROSS	NET	GROSS	NET	GROSS	NET
Development:						
Oil	6	.45	2	.35	--	--
Gas	4	3.17	--	--	--	--
Non-productive	--	--	--	--	--	--
Total	10	3.62	2	.35	--	--
Exploration:						
Oil	--	--	1	.20	2	0.26
Gas	3	2.00	2	2.00	5	3.79
Non-productive	12	5.77	6	2.29	2	1.20
Total	15	7.77	9	4.49	9	5.25

We owned working and royalty interests in approximately 246 gross (6.7 net) producing oil and 288 gross (29.9 net) producing gas wells as of December 31, 2001. 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, 2001, we had 3 gross (.53 net) wells with multiple completions. At December 31, 2001, we had 1 gross (.15 net) development oil well and 1 gross (1 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, 2001.

	LEASEHOLD ACREAGE			
	DEVELOPED		UNDEVELOPED	
LOCATION	GROSS	NET	GROSS	NET

Alabama	19,451	16,635	80	2
Louisiana	8,178	5,221	3,795	1,212
Other States	860	388	934	744
Federal Waters	127,966	85,196	341,995	117,748
Total	156,455	107,440	346,804	119,706

As of December 31, 2001, we owned various royalty and overriding royalty interests in 1,336 net developed and 6,862 undeveloped acres. In addition, we owned 5,184 developed and 120,816 undeveloped mineral acres.

MAJOR CUSTOMERS

Our production is sold 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:

	DECEMBER 31,		
	2001	2000	1999
Adams Resources Marketing, Ltd.	--	14%	16%
Columbia Energy Services	--	--	29%
Dynegy	8%	--	12%
Prior Energy Corporation	20%	--	--
Reliant Energy Services	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.

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 2001.

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.

	QUARTER ENDED	HIGH	LOW
2000:			
	First quarter	$ 15.625	$ 9.625
	Second quarter	16.500	10.625
	Third quarter	17.625	12.500
	Fourth quarter	17.188	12.938
2001:			
	First quarter	$ 16.688	$10.000
	Second quarter	13.220	10.650
	Third quarter	11.820	5.900
	Fourth quarter	7.200	5.350

As of March 18, 2002, there were approximately 5,036 common stockholders of record.

We have not 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, 2001 have 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)

	YEARS ENDED		
	2001	2000	19
STATEMENT OF OPERATIONS DATA:			
Revenues:			
Oil and gas sales	$ 60,010	$ 56,310	$ 3
Interest and other	1,742	1,767	
Total revenues	61,752	58,077	3
Costs and expenses:			
Lease operating expenses	11,252	9,339	
Depreciation, depletion and amortization	21,081	17,153	1
General and administrative	4,635	4,155	
Writedown of Enron derivatives	9,186	--	
Interest	12,805	8,420	
Accelerated vesting and retirement benefits	--	--	
Impairment of oil and gas properties	--	--	
Total costs and expenses	58,959	39,067	3
Income (loss) from operations	2,793	19,010	
Income tax expense (benefit)	977	6,463	
Net income (loss)	1,816	12,547	
Preferred stock dividends	1,277	2,403	
Net income (loss) available to common shares	$ 539	$ 10,144	$
Net income (loss) per common share:			
Basic	$ .04	$ .82	$
Diluted	$ .04	$ .80	$
Shares used in computing net income (loss) per common share:			
Basic	13,273	12,420	
Diluted	13,366	12,745	
BALANCE SHEET DATA (END OF PERIOD):			
Oil and gas properties, net	$ 343,158	$ 258,613	$ 19
Total assets	$ 372,095	$ 301,569	$ 25
Long-term debt, less current portion	$ 161,733	$ 134,000	$ 10
Stockholders' equity	$ 147,224	$ 136,328	$ 12

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, 2001 to 303 billion cubic feet of natural gas equivalent (Bcfe). This represents a decrease of 9% over previous year-end 2000 estimated proved reserves of 334 Bcfe. This decrease in 2001 is primarily due to production and revisions exceeding exploration additions to the reserve base. These reserve estimates include 1.2 Bcfe at December 31, 2001 and 3.5 Bcfe at December 31, 2000 dedicated to a volumetric production payment.

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 92% of the budgeted 2002 production and 40% of proved reserves at year-end 2001.

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 July 2001, the Financial Accounting Standards Board approved Statement of Accounting Standards No. 143, Asset Retirement Obligations ("SFAS 143"). SFAS 143 will require that the fair value of abandonment

obligations be reflected as a liability, resulting in a corresponding increase to the historical cost of the related assets and potentially an adjustment for the cumulative effect of a change in accounting principle. This standard is required to be adopted by us beginning no later that January 1, 2003. We have not yet determined timing or the impact of the adoption of SFAS 143.

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. We include in such amounts 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. Our 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 do not include any costs related to our production or our general corporate overhead. Costs associated with unevaluated properties 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 our management determines these costs have been impaired and increase our depletion rates as they are transferred to evaluated property.

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. Increases in these costs increase our depletion rates. Additions to reserves decrease our depletion rates.

Under the full cost accounting rules of the SEC, we reviewed the carrying value of our proved oil and gas properties each quarter on a country-by-country basis. 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 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 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 our auditor's report. Given the volatility of oil and gas prices, it is reasonably possible that our estimates 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. Based on prices at December 31, 2001 we would have been required to writedown our assets by $37.5 million. However, as of the date of our auditor's report, commodity prices increased sufficiently to eliminate any writedown.

Upon the acquisition or discovery of oil and gas properties, we estimate 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. These cost estimates, if revised upward for future changes, could increase our depletion rate.

The estimates used to calculate our oil and gas reserves are imprecise and are based on assumptions about future production levels, prices and future operating costs. As a result, the quantity of our proved reserves may be subject to downward or upward adjustment as additional information or analysis become available. In addition, estimates of the economically recoverable oil and gas reserves, classifications of such reserves,

and estimates of future net cash flows, prepared by different engineers or by the same engineers at different times, may vary substantially. In particular, the assumptions regarding the timing and costs to commence production from our deepwater wells used in preparing our reserves are subject to revisions over time. These assumptions could affect quantities used to calculate depletion and any significant revisions to our reserves could impact our depletion computations.

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 2001 by $5.0 million. Cash provided from operating activities during 2001 totaled $35.2 million. Dividends paid on preferred stock were $1.3 million. Average debt outstanding was $164.9 million during 2001 compared to $118.3 million in 2000. At December 31, 2001, we had working capital of $.4 million, excluding current maturities of long-term debt and liabilities to be refinanced.

In May 2001, we initiated a combination of offerings of equity and senior notes to investors with proceeds to be used to call certain of our subordinated debt, repay borrowings under our senior secured credit facility and to finance capital expenditures. Subsequently, we withdrew our offer to sell the senior notes and the equity sale was terminated. Approximately $358,000 of costs associated with the withdrawn offering were expensed during the second quarter.

In early July of 2001, we closed a $95 million multiple advance term loan 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. The Credit Facility currently provides for a $50 million borrowing base ("Borrowing Base"), which is adjusted periodically on the basis of a discounted present value of future net cash flows attributable to our proved producing oil and gas reserves as determined by the bank. We may borrow, pay, reborrow and repay under the Credit Facility until July 31, 2002, on which date, we must repay in full all amounts then outstanding. The maturity date can be extended to July 31, 2004 if redemption of the 10.125% Senior Subordinated Notes due September 15, 2002 is completed prior to July 31, 2002. We expect to redeem or extend the Notes due in September 2002 prior to their maturity and anticipate extensions of maturity of the Credit Facility to July 2004. At December 31, 2001, availability under the Credit Facility was $50 million.

The Credit Facility and the 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, 2001.

Our plans for 2002 include non-discretionary capital expenditures of $50 million. Approximately $23 million of the investment will be allocated to the development of two of our deepwater discoveries. Our non-discretionary expenditure on the shelf includes the completion of a production acceleration project in the Mobile Block 864 area, well completions for 2001 discoveries and other commitments to existing properties.

Cash flow and current availability under the Credit Facility, subject to the maturity of the same as discussed above, is expected to be sufficient to fund our 2002 non-discretionary capital expenditures. These expenditures include completion of the Medusa deepwater discovery, currently scheduled to begin production late in the fourth quarter of 2002 or early 2003. We are currently evaluating options for redeeming the Senior Subordinated Notes due 2002. These options include, but are not limited to, (i) negotiated extensions of the maturity of a portion of these notes, (ii) increased availability under the Credit Facility and (iii) the issuance of additional Senior Notes.

We anticipate that these options would provide necessary capital to enable us to

continue our operational activities until such time as production from the Medusa discovery begins. At that time, we anticipate the inclusion of the Medusa reserves and production will be integrated in our borrowing base from our Credit Facility and provide available borrowing capacity as well as cash flow from the new production for future discretionary capital expenditures.

Options currently under consideration to provide longer-term liquidity include (i) the sale of one of our deepwater discoveries, (ii) lease or similar financing of our deepwater infrastructure particularly at Medusa and (iii) the sale of common equity.

The following table describes our outstanding contractual obligations (in thousands) as of December 31, 2001:

CONTRACTUAL OBLIGATIONS	TOTAL	LESS THAN ONE YEAR	ONE-THREE YEARS	FOUR-FIVE YEARS	AF
Credit Facility	$ 100	$ 100	--	--	
Senior Notes	95,000	--	--	$ 95,000	
10.125% Senior Subordinated Debt	36,000	36,000	--	--	
10.25% Senior Subordinated Debt	40,000	--	$ 40,000	--	
			--	--	
11% Senior Subordinated Debt	33,000	--	--	33,000	
Capital lease (future minimum payments)	8,413	2,175	3,863	1,138	$

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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, 2001.

	DECEMBER 31,		
	2001(a)(b)	2000(a)(b)	1999(a)(b)
Production:			
Oil (MBbls)	273	232	330
Gas (MMcf)	13,566	13,943	14,606
Total production (MMcfe)	15,206	15,334	16,589
Average daily production (MMcfe)	41.7	41.9	45.5
Average sales price:			
Oil (per Bbl)	$ 22.95	$ 27.88	$ 12.16
Gas (per Mcf)	$ 3.96	$ 3.57	$ 2.27
Total production (per Mcfe)	$ 3.95	$ 3.67	$ 2.24
Average costs (per Mcfe):			
Lease operating expenses	$ .73	$ .61	$ .46
Depletion	$ 1.37	$ 1.10	$ .99

General and administrative (net of management fees)	$ .30	$ .27	$ .28

(a) Includes hedging gains and losses.

(b) Includes volumes of 2,300 MMcf for each of the years 2001 and 2000 and volumes of 1,300 MMcf in 1999, at an average price of $2.08 per Mcf associated with a volumetric production payment.

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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 have been 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 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 its reserve quantity estimates, its long-term outlook for oil and gas prices and its expected level of future revenues and expenses. We believe it is more likely than not, based upon this evaluation, that it 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, 2000 AND 1999

OIL AND GAS REVENUES

Oil and gas revenues for 2000 were $56.3 million, a 52% increase from the 1999 amount of $37.1 million. However, 2000 oil and gas production of 15,334 MMcfe decreased by 8% from the 1999 amount of 16,589 MMcfe.

Oil production decreased from 330,000 barrels in 1999 to 232,000 barrels in 2000 but the average sales price increased from $12.16 in 1999 to $27.88 in 2000. As a result, oil revenues went from $4.0 million in 1999 to $6.5 million in 2000. The decrease in oil production was primarily from older properties' normal and expected decline in production and the depletion of Main Pass 31. The significant increase in oil revenue was due to the price of oil received for 2000 oil production more than doubling over 1999 average prices.

Gas revenues for 2000 were $49.8 million based on sales of 13.9 Bcf at an average sales price of $3.57 per Mcf. For 1999, gas revenues were $33.1 million based on production of 14.6 Bcf sold at an average sales price of $2.27 per Mcf.

When compared to 1999, production decreased due to a combination of older properties' normal and expected decline in production and the depletion of Main Pass 31. This decrease was offset by production gains at East Cameron Block 275 and South Marsh Island 261 as they began production in early 2000. East Cameron Block 275 experienced a significant drop in the fourth quarter of 2000 due to work on the host platform, which caused the well to be shut in for the entire quarter. This property was back online in January 2001 and currently is producing at or near levels prior to the shut-in. Gas revenue increased due to higher prices received for production in 2000, especially in the fourth quarter, compared to 1999 offset by the 5% decline in gas production.

LEASE OPERATING EXPENSES AND SEVERANCE TAXES

Lease operating expenses, including severance taxes, increased from $7.5 million ($.46 per Mcfe) in 1999 to $9.3 million ($.61 per Mcfe) in 2000. The increase per Mcfe is primarily attributable to production declines in 2000 related to older properties that have relatively fixed operating costs, which contributed to the higher per Mcf costs.

DEPRECIATION, DEPLETION AND AMORTIZATION

Depreciation, depletion and amortization increased by almost 3% due to an increase in the amortization base by 56%, primarily as a result of increased future development costs over 1999 offset by a 28% increase in reserves and by a decrease in production.

Total charges increased from $16.7 million, or $1.01 per Mcfe in 1999 to $17.2 million, or $1.12 per Mcfe in 2000.

GENERAL AND ADMINISTRATIVE

General and administrative expenses for 2000 were $4.2 million, or $.27 per Mcfe, compared to $4.6 million, or $.28 per Mcfe, in 1999. This 9% decrease is primarily due to an increase in direct overhead allocable to employees engaged in the acquisition, exploration and development of oil and gas properties in 2000.

INTEREST EXPENSE

Interest expense for 2000 and 1999 was $8.4 million and $6.2 million, respectively. This increase is a result of the increase in interest rates and in average debt outstanding in 2000 versus 1999. This average debt outstanding increase is directly related to the Senior Subordinated Notes issued in October 2000 and borrowings under the Credit Facility during the year.

INCOME TAXES

Our 2000 results include a deferred income tax expense of $6.5 million. We have 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

Our revenues are derived from the sale of our crude oil and natural gas production. From time to time, we have entered into hedging transactions that lock in for specified periods the prices we will receive for the production volumes to which the hedge relates. The hedges reduce exposure on the hedged volumes to decreases in commodities prices and limit the benefit might otherwise have received from any increases in commodities prices on the hedged volumes.

We have put options in effect for 2002, other than those certain Enron North America Corp. derivatives discussed previously under Management Discussion and Analysis of Financial Condition and Results of Operation-Comparison of Results of Operations for the Years Ended December 31, 2001 and 2000 and in Note 6 of the financial statements. In March 2002, we purchased put options, which established an average floor price of $2.65 per Mcf on 6.1 Bcf of production from April 2002 through September 2002.

Based on projected annual sales volumes for 2002 (excluding forecast production increases over 2001), a 10% decline in the prices we receive for our crude oil and natural gas production would have an approximate $4.0 million impact on our revenues.

ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

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REPORT OF INDEPENDENT PUBLIC ACCOUNTANTS

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

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

	DECEMBER 31,	
	2001	2000
ASSETS		
Current assets:		
Cash and cash equivalents	$ 6,887	$ 11,876
Accounts receivable	5,908	9,244

Advance to operators	--	1,131
Other current assets	209	207
Total current assets	13,004	22,458
Oil and gas properties, full-cost accounting method:		
Evaluated properties	704,937	589,549
Less accumulated depreciation, depletion and amortization	(399,339)	(378,589)
	305,598	210,960
Unevaluated properties excluded from amortization	37,560	47,653
Total oil and gas properties	343,158	258,613
Pipeline and other facilities, net	5,364	5,537
Other property and equipment, net	2,455	1,790
Deferred tax asset	4,399	8,573
Long-term gas balancing receivable	473	643
Other assets, net	3,242	3,955
Total assets	$ 372,095	$ 301,569
LIABILITIES AND STOCKHOLDERS' EQUITY		
Current liabilities:		
Accounts payable and accrued liabilities	$ 9,985	$ 17,842
Undistributed oil and gas revenues	1,131	1,411
Accrued net profits interest payable	1,501	2,146
Accounts payable and accrued liabilities to be refinanced	9,558	--
Current maturities of long-term debt	37,345	--
Total current liabilities	59,520	21,399
Long-term debt-excluding current maturities	161,733	134,000
Deferred revenue on sale of production payment	2,406	7,236
Accrued retirement benefits	137	1,886
Long-term gas balancing payable	1,075	720
Total liabilities	224,871	165,241
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, 2001 with a liquidation preference of $15,021,525	6	6
Common Stock, $.01 par value; 20,000,000 shares authorized; 13,397,706 and 13,327,675 shares outstanding at December 31, 2001 and 2000, respectively	134	133
Treasury stock (99,078 shares at cost)	(1,183)	(1,183)
Capital in excess of par value	155,608	151,223
Accumulated other comprehensive income	5,971	--
Retained earnings (deficit)	(13,312)	(13,851)
Total stockholders' equity	147,224	136,328

Total liabilities and stockholders' equity	$ 372,095	$ 301,569

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

CALLON PETROLEUM COMPANY
CONSOLIDATED STATEMENTS OF OPERATIONS
FOR THE YEARS ENDED DECEMBER 31, 2001, 2000 AND 1999
(IN THOUSANDS, EXCEPT PER SHARE AMOUNTS)

	2001	2000	1999
Revenues:			
Oil and gas sales	$ 60,010	$ 56,310	$ 37,140
Interest and other	1,742	1,767	1,853
Total revenues	61,752	58,077	38,993
Costs and expenses:			
Lease operating expenses	11,252	9,339	7,536
Depreciation, depletion and amortization	21,081	17,153	16,727
General and administrative	4,635	4,155	4,575
Writedown of Enron derivatives	9,186	--	--
Interest	12,805	8,420	6,175
Total costs and expenses	58,959	39,067	35,013
Income from operations	2,793	19,010	3,980
Income tax expense	977	6,463	1,353
Net income	1,816	12,547	2,627
Preferred stock dividends	1,277	2,403	2,497
Net income available to common shares	$ 539	$ 10,144	$ 130
Net income per common share:			
Basic	$ .04	$ .82	$ .01
Diluted	$ .04	$ .80	$ .01

Shares used in computing net income per common share:			
Basic	13,273	12,420	8,976
Diluted	13,366	12,745	9,075

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

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

	PREFERRED STOCK	COMMON STOCK	TREASURY STOCK	CAPITAL IN EXCESS OF PAR VALUE	ACCUMULATE OTHER COMPREHENSI INCOME
Balances, December 31, 1998	$ 13	$ 82	$ (915)	$ 109,429	$ --
Net income	--	--	--	--	--
Sale of common stock	--	37	--	40,994	--
Preferred stock dividends	--	--	--	--	--
Shares issued pursuant to employee benefit and option plan	--	--	--	274	--
Employee stock purchase plan	--	--	--	67	--
Restricted stock plan	--	(2)	--	(1,613)	--
Conversion of preferred shares to common stock	(2)	5	--	274	--
Stock buyback plan	--	--	(268)	--	--
Balances, December 31, 1999	11	122	(1,183)	149,425	--
Net income	--	--	--	--	--
Preferred stock dividends	--	--	--	--	--
Shares issued pursuant to employee benefit and option plan	--	--	--	1,069	--
Employee stock purchase plan	--	--	--	269	--
Tax benefits related to stock compensation plans	--	--	--	41	--
Conversion of preferred shares to common	(5)	11	--	419	--
Balances, December 31, 2000	6	133	(1,183)	151,223	--
Comprehensive income:					
Net income	--	--	--	--	--
Other comprehensive income	--	--	--	--	5,971
Total comprehensive income					

Preferred stock dividends	--	--	--	--	--
Shares issued pursuant to employee benefit and option plan	--	1	--	942	--
Employee stock purchase plan	--	--	--	357	--
Tax benefits related to stock compensation plans	--	--	--	18	--
Warrants	--	--	--	3,068	--
Balances, December 31, 2001	$ 6	$ 134	$ (1,183)	$ 155,608	$ 5,971

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, 2001, 2000 AND 1999
(IN THOUSANDS)

	2001
Cash flows from operating activities:	
Net income	$ 1,816
Adjustments to reconcile net income (loss) to cash provided by operating activities:	
Depreciation, depletion and amortization	21,709
Amortization of deferred costs	2,485
Amortization of deferred production payment revenue	(4,830)
Writedown of Enron derivatives	9,186
Deferred income tax expense	977
Noncash charge related to compensation plans	942
Changes in current assets and liabilities:	
Accounts receivable	3,336
Advance to operators	1,131
Other current assets	(2)
Current liabilities	(8,782)
Increase in accounts payable and accrued liabilities to be refinanced	9,558
Change in gas balancing receivable	170
Change in gas balancing payable	355
Change in other long-term liabilities	(1,749)
Change in other assets, net	(1,071)
Cash provided (used) by operating activities	35,231
Cash flows from investing activities:	
Capital expenditures	(113,833)
Cash proceeds from sale of mineral interests	1,195
Cash provided (used) by investing activities	(112,638)
Cash flows from financing activities:	

Equity issued related to employee stock plans	357
Purchase of treasury shares	--